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RICHARD L. BRODSKY
Assemblyman 92ND District

Westchester County

CHAIRMAN
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Corporations, Authorities
and Commissions

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February 19, 2008 (8:30am)

OFFICE OF SECRETARY
RULEMAKINGS AND
ADJUDICATIONS STAFF

February 15, 2008

Office of the Secretary
U.S. Nuclear Regulatory Committee
Sixteenth Floor
One White Flint North
11555 Rockville Pike
Rockville, Maryland 20852

Re; Indian Point License Renewal, Docket No. 50-247/286-LR

To Whom It May Concern:

Enclosed please find Petitioners Westchester Citizen's Awareness Network (WestCAN), Rockland County Conservation Association, Inc (RCCA), Promoting Health and Sustainable Energy, Inc. (PHASE), Sierra Club – Atlantic Chapter (Sierra Club), and New York State Assemblyman Richard L. Brodsky Reply Brief in response to the NRC Staff and Entergy.

Also enclosed is the original signed hard copy of the Reply, the Certificate of Service, Table of Contents, Exhibits. A courtesy CD-ROM is being sent separately.

As you are aware I was experiencing problems with the NRC's server as we discussed with Rebecca Gitter. We transmitted the document as a word file, but are concerned it may be corrupted, if it arrived at all. We transmitted an Adobe PDF file via another office which we believe successfully went to all the parties. Therefore please delete the first transmittal, the "word document", and consider the Abode PDF file the Reply.

Sincerely,

Sarah L. Wagner

TEMPLATE=SECY-037

SECY-02

ALBANY OFFICE: Room 422, Legislative Office Building, Albany, New York 12248, (518) 455-5753
DISTRICT OFFICE: 5 West Main Street, Suite 205, Elmsford, New York ...

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
	)	
ENTERGY NUCLEAR OPERATIONS, INC.	)	Docket Nos. 50-247/286-LR
(Indian Point Nuclear Generating) Units 2 and 3)	)	
	)	

CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing Reply of WestCAN et al. dated February 15, 2008, have been served upon the following by electronic mail where email address provided, this 15th day of February, 2008 and a signed original and two paper copies have been deposit with a courier service on the Office of the Secretary, U.S. Nuclear Regulatory, Sixteenth Floor, One Flint North, 11555 Rockville Pike Rockville, Maryland 20852, and a courtesy paper copy has been sent to Staff:

Lawrence G. McDade, Chair
Atomic Safety and Licensing Board Panel
Mail Stop – T-3 F23
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001
E-mail: LGM1@nrc.gov

Dr. Richard E. Wardwell
Atomic Safety and Licensing Board Panel
Mail Stop – T-3 F23
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001
E-mail: REW@nrc.gov

Dr. Kaye D. Lathrop
Atomic Safety and Licensing Board Panel
190 Cedar Lane E.
Ridgeway, CO 81432
E-mail: KDL2@nrc.gov

Atomic Safety and Licensing Board Panel
U. S. Nuclear Regulatory Commission
Mail Stop – T-3 F23

Office of Commission Appellate Adjudication
U. S. Nuclear Regulatory Commission
Mail Stop: O-16G4
Washington, D.C. 20555-0001
Email: OCAAMAIL@nrc.gov

Office of the Secretary
Attn: Rulemaking and Adjudications Staff
Mail Stop: O-16G4
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001
Email: HEARINGDOCKET@nrc.gov

Zachary S. Kahn, Law Clerk
Atomic Safety and Licensing Board Panel
Mail Stop – T-3 F23
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001
Email: ZXK1@nrc.gov

Washington, D.C. 20555-0001
William C. Dennis, Esq.

Assistant General Counsel
Entergy Nuclear Operations, Inc.
440 Hamilton Avenue
White Plains, NY 10601
Email: wdennis@entergy.com
Sherwin.turk@nrc.gov
Beth.mizuno@nrc.gov

Kathryn M. Sutton, Esq.
Paul M. Bessette, Esq.
Martin J. O'Neill, Esq.
Morgan, Lewis & Bockius, LLP
1111 Pennsylvania Avenue, NW
Washington, D.C. 20004
E-mail: ksutton@morganlewis.com
E-mail: pbessette@morganlewis.com
E-mail: martin.o'neill@morganlewis.com

Michael J. Delaney, Esq.
Vice President – Energy Department
New York City Economic Development
Corporation (NYCDEC)
110 William Street
New York, NY 10038
E-mail: mdelaney@nycedc.com

John LeKay
FUSE USA
351 Dyckman Street
Peekskill, NY 10566
E-mail: fuse_usa@yahoo.com

Arthur J. Kremer, Chairman
New York Affordable Reliable Electricity
Alliance (AREA)
347 Fifth Avenue, Suite 508
New York, NY 10016
E-mail: ajkremer@rmfp.com
kremer@area-alliance.org

Diane Curran, Esq.

Manna Jo Greene
Hudson River Sloop Clearwater, Inc.
112 Little Market Street
Poughkeepsie, NY 12601
Email: Mannaio@clearwater.org

Justin D. Pruyne, Esq.
Assistant County Attorney
Office of the Westchester County Attorney
148 Martine Avenue, 6th Floor
White Plains, NY 10601
E-mail: jdp3@westchestergov.com

Daniel E. O'Neill, Mayor
James Seirmarco, M.S.
Village of Buchanan
Municipal Building
Buchanan, NY 10511-1298
E-mail: vob@bestweb.net

John J. Sipos, Esq.
Charlie Donaldson, Esq.
Assistants Attorney General
New York State Department of Law
Environmental Protection Bureau
The Capitol
Albany, NY 12224
E-mail: john.sipos@oag.state.ny.us

Joan Leary Matthews, Esq.
Senior Attorney for Special Projects
New York State Department of
Environmental Conservation
Office of the General Counsel
625 Broadway, 14th Floor
Albany, NY 12233-1500
E-mail: jlmatthe@gw.dec.state.ny.us

Harmon, Curran, Spielberg & Eisenberg, LLP
1726 M Street, NW, Suite 600
Washington, D.C. 20036
E-mail: dcurran@harmoncurran.com

Robert Snook, Esq.
Office of the Attorney General
State of Connecticut
55 Elm Street
P.O. Box 120
Hartford, CT 06141-0120
E-mail: robert.snook@po.state.ct.us

Victor Tafur, Esq.
Phillip Musegaas, Esq.
Riverkeeper, Inc.
828 South Broadway
Tarrytown, NY 10591
E-mail: phillip@riverkeeper.org
vtafur@riverkeeper.org

Daniel Riesel, Esq.
Thomas F. Wood, Esq.
Ms. Jessica Steinberg, J.D.
Sive, Paget & Riesel, P.C.
460 Park Avenue
New York, NY 10022
E-mail: driesel@sprlaw.com
jsteinberg@sprlaw.com

Elise N. Zoli, Esq.
Goodwin Procter, LLP
Exchange Place
53 State Street
Boston, MA 02109
E-mail: ezoli@goodwinprocter.com

Ms. Nancy Burtop
147 Cross Highway
Redding Ridge, CT 06876
E-mail: nancyburtonct@aol.com

Kimberly A. Sexton
Counsel for NRC Staff
U.S. Nuclear Regulatory Commission
Office of the General Counsel
Washington, D.C. 20555
E-mail: kimberly.sexton@nrc.gov

Janice A. Dean
Assistant Attorney General
Office of the Attorney General
120 Broadway, 26th Floor
New York, NY 10271
E-mail: janice.dean@oag.state.ny.us

Christopher C. Chandler
U.S. Nuclear Regulatory Commission
Office of the General Counsel
Washington, D.C. 20555
E-mail: christopher.chandler@nrc.gov

Sarah L. Wagner

Sarah L. Wagner, Esq.

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Exhibit D	Power Authority of the State of New York and the Consolidated Edison Company, "Indian Point Probabilistic Safety Study," Spring 1982. 3 Nuclear Regulatory Commission, NUREG/CR-2859, "Evaluation of Aircraft Crash Hazards Analyses for Nuclear Power Plants," June 1982	19820300-ip-probabilistic-risk-assessment-1-of-2.pdf 19820300-ip-probabilistic-risk-assessment-2-of-2.pdf	Pg.41
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Exhibit I	Amendment Nine of the Operating License	Provided with petition and as clarifed	Pg. 71
Exhibit J	GZA Environmental, Inc. "Hydogeologic Site Investigation Report, Indian Point Entergy Center, January 7, 2008, file No. 41.0017369.10	(Provided by Entergy in January 22 Response—therefore not supplied here)	Pg. 5 of Exhibit F
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Exhibit N	Audit of NRC's License Renewal Program OIG-07-A-15 September 6, 2007	OIG report on License Renewal.pdf	
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Exhibit P	NRC BULLETIN 2003-02: leakage from reactor pressure vessel lower Head penetrations and reactor coolant pressure Boundary integrity	Bulletin 2003-02 and IP response b.pdf	Page 86, page 6 of Exhibit Q
Exhibit Q (Note that Exhibit Q as reference on page 104 should be Exhibit M)	Supplemental Declaration of Ulrich Witte regarding misrepresentation of design, construction and operation of Unit 2 and Unit 3 to draft GDCs.	GDC Declaration Supplmental.pdf	Pg. 86, p104
Exhibit R	Flow-Accelerated Corrosion failures.	Oct 2007 repair to service water	Page 104; page xx of

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Exhibit S	Petitioners further claim that Entergy has failed to demonstrate "a good track record with use of CHECWORKS." We note with interest that this same program implemented another Entergy plant currently in renewal proceedings, and was not just admitted, but also denied motion for summary disposition only months ago		Page 104
Exhibit T	Identical program		p105
Exhibit U	Atomic Industry Forum... Trade comments to draft General Design Criteria and Erroneously claim of publication in the Federal Register for public comment in July, 1967	See petition filed December 10 and clarified	Pg. 71
Exhibit V	General Design Criteria for the LRA and subsequently approved by the Atomic Energy Commission under the 1970 Safety Evaluation Report	See petition filed December 10 and clarified	Pg. 72
Exhibit W	Documents cited or submitted in the applicant's LRA. The commission dealt with the design basis and license failures with a stroke of a pen in 1992	See petition filed December 10	Pg. 4 of Exhibit Q
Exhibit Y	Technical Spec Bases Requirements, update of 2004.	IP3 Technical Specifications Bases Manual October 2004	Pg. 84; Page 5 of Exhibit Q
Exhibit Z.	General Design Criteria 45(p 14)	See exhibit Z at page 14 form original petition	Pg. 85
Exhibit AA	Baffle bolt testing: alter chemistry tests vs. automated testing components such as baffle bolts that hold down springs, lower core barrel, and lower core plate are routinely UT or VT'd during outages and often replaced	See petition filed December 10 and clarified	Pg. 85

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Exhibit CC	1992 letter	See petition filed December 10 and clarified	Pg.88
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Exhibit EE	Audit of NRC's License Renewal Program OIG-07-A-15 September 6, 2007	Provided under Exhibit N	p 89
Exhibit FF	Office instruction for Nuclear Reactor Regulation LIC-100	Provide also under Exhibit Q	p 89

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION
ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:
Lawrence G. McDade, Chairman
Dr. Kaye D. Lathrop
Dr. Richard E. Wardwell

In the Matter of	)	Docket Nos.
	)	50-247 and 59-286-LR
ENTERGY NUCLEAR OPERATIONS, INC	)	
	)	ASLB No. 07-858-03
	)	LR-BD01
(Indian Point Nuclear Generating Units 2 and 3)	)	

REPLY OF PETITIONERS WESTCHESTER CITIZEN'S AWARENESS NETWORK (WESTCAN), ROCKLAND COUNTY CONSERVATION ASSOCIATION, INC. (RCCA), PUBLIC HEALTH AND SUSTAINABLE ENERGY (PHASE), SIERRA CLUB - ATLANTIC CHAPTER (SIERRA CLUB), AND RICHARD L. BRODSKY

PRELIMINARY STATEMENT

The following constitutes the reply of Petitioners Westchester Citizen's Awareness Network (WestCAN), Rockland County Conservation Association, Inc. (RCCA), Public Health and Sustainable Energy (PHASE), Sierra Club - Atlantic Chapter (Sierra Club), and New York State Assemblyman Richard L. Brodsky (hereinafter "Petitioners"). Petitioners assert that they have standing to intervene and have proffered admissible contentions in accordance with 10 C.F.R. 2.309(f).

PROCEDURAL HISTORY

On April 23, 2007, and supplemented on May 3, 2007 and June 21, 2007, Entergy Nuclear Operations, Inc. (hereinafter "Entergy" or "licensee") filed an application to renew its operating license for an additional twenty year period for Indian Point Nuclear Generating Units 1 and 2. Notice of Acceptance for Docketing of the Application and Notice of Opportunity for Hearing was published in the Federal Register on August 1, 2007 regarding Entergy's license renewal application. On October 1, 2007, the U.S. Nuclear Regulatory Commission (hereinafter "NRC" or Commission") extended the period for filing requests for hearings until November 31, 2007. Petitioners were granted an extension to file their Petition on or before December 10, 2007.

On December 10, 2007, Petitioners electronically by email served a Petition for Leave to Intervene with Contentions and a Request for a Hearing. On December 11, 2007, hard copies of said Petition and exhibits were served on the Office of the Secretary at the Nuclear Regulatory Commission (hereinafter "NRC") by Fed Ex.

By Order dated November 27, 2007, Entergy and the NRC staff were ordered to file answers on or before January 22, 2008. The NRC staff served an Answer to the Petition electronically by email on January 22, 2008, at 11:59pm. The licensee, Entergy, electronically by email served a reply to the Petition on electronically by email on January 22, 2008, with referenced exhibits arriving on January 27, 2008. Pursuant to Order by the Licensing Board on January 29, 2008, Petitioners replies are due on or before February 15, 2008.

BACKGROUND OF INDIAN POINT LICENSE RENEWAL APPLICATION AND CONTENTIONS RAISED BY THE COALITION PETITIONERS

The United States operates 104 nuclear power reactors, which provide nearly 20 percent of the nation's electricity. More than half have had their original 40-year operating licenses renewed for an additional 20 years. Encouraged by billions of dollars in subsidies and incentives in the 2005 Energy Bill, a handful of companies applied for licenses to build new reactors last fall, and other companies are expected to apply later this year. Recurring lessons from the past consistently inform us that unless the Nuclear Regulatory Commission (NRC) undergoes major reforms, nuclear power will remain both riskier and more expensive than necessary. Indian Point is of particular risk to the public assets and the health and safety of the public given its location, age, non-compliant design, and legacy history evidenced by the oversight record by the regulator.

The NRC is the federal agency primarily responsible for establishing and enforcing safety regulations for nuclear power. Whereas this petition does not challenge the adequacy of rulemaking, it does challenge adequacy of articulating and interpreting the rules by the Applicant and the lack of substantive review by Staff as to whether specific concrete contentions are truly useful in establishing via engineering rigor and examination of the rule of law, confirming there is adequate safety, and lawful environmental protection of the Indian Point plant. This requirement begins with design requirements imposed on the Applicant contained, continues through approval of the original design criteria committed by the applicant by the record decades ago, through a total period of 40 years from construction to decommissioning.

That design lifetime is articulated in the Current Licensing Basis. The regulator has an express time limit presently in effect to operate each reactor. Unit 2 license expires in 2013, and Unit 3 in 2015.

The applicant is now attempting to substantiate that it can continue to operate the plant beyond its engineered life, and the NRC is compelled under law to rigorously evaluate this proposal, and recommend to the commission that commission can meet is statutory mandate of protecting the health and safety of the public and minimizing risk to public assets in granting this extension.

The results of this exceeding important mantel placed upon the Commission is frankly cause for the community to be concerned. Numerous third parties and government oversight agencies agree. The Union of Concerned Scientists has monitored nuclear power safety issues since the early 1970s. Amongst the 104 operating plants, a disproportionally large segment of its efforts have been directed at getting the NRC to enforce regulations already on the books so as Entergy at Indian Point recognize and adhere to its burden of maintaining a sound record of compliance to its license basis, and maintains the CLB itself as defined under 10 C.F.R. Part 54 section 54.3.

A particular and on point example is the Applicant's description of its fire protection program contained in its application. Entergy's program has significant safety issues presently unresolved, yet a program that must have compliance integrity to count on for limiting the renewal scope. But it does not. See WestCAN et al., Objection to Fire Protection Exemption…" Evaluations conducted by the Government Accountability Office (GAO) and the NRC's Inspector General (IG) confirm our perspective: These reports repeatedly identify inadequate enforcement of existing regulations by the NRC, with the most recent regarding the exact issue at Indian Point, and raised contentions 5 through 11B.

The nexus of a broken present fire protection program cannot be set aside in the renewal process if there is no prospect for correcting the deficient condition. As history shows, the results are catastrophic.

For example, in its May 2004 report, "Nuclear Regulation: NRC Needs to More Aggressively and Comprehensively Resolve Issues Related to the Davis-Besse Nuclear Power Plant's Shutdown" , the GAO concluded, "[The] NRC should have but did not identify or prevent the corrosion at Davis-Besse [a nuclear power plant in Ohio] because both its inspections at the plant and its assessments of the operator's performance yielded inaccurate and incomplete information on plant safety conditions."

More recently and on point to license renewal and Entergy's failure to comply with the rule are six apparent violations found by an NRC inspection that took seven unplanned plant shutdowns on Unit 3 in less than a year to trigger.

The core and essential of license renewal is a sound foundation that provides confidence on safely minimizing renewal scope to when all parties will agree is under the rules a very narrow scope. The record demonstrates otherwise, and compels us to raise as acceptable scope a program that is presently deficient but counted on as sufficient so as to exclude it from renewal scope. Where the program, system, structure or component is defective, and is presently unreconciled to correct, we argue under the rules defined in 10 C.F.R. 54 that it cannot be excluded from license renewal. It represents ex post facto material items that bear on the health and safety of the public and minimizing risk to public assets.

The IG's January 2008 report, "NRC's Oversight of Hemyc Fire Barriers" documents the NRC's repeated failure to enforce fire-protection regulations. In March 1993, after problems surfaced with the Thermo-Lag fire barrier used by nearly 100 reactors, the NRC chairman committed to evaluate all fire barriers used in U.S. nuclear reactors. Tests conducted by the National Institute of Standards and Technology in 1993 (and reported to the NRC in 1994) found that the one-hour Hemyc fire barrier, used by 17 nuclear reactors, failed in 23 minutes. The NRC considered these tests too small to be conclusive and stated that larger-scale testing was needed. However, it wasn't until 2005 that the NRC commissioned such testing--even though the NRC acquired yet more evidence of problems with Hemyc in 2000. After an inspection found that Hemyc was used more extensively than assumed at one U.S. plant, the NRC reviewed the Hemyc tests conducted by the vendor and found that they did not demonstrate that Hemyc could meet its one-hour or three-hour ratings. When the larger-scale tests were finally conducted by Sandia National Laboratory, the one-hour Hemyc fire barrier failed in 13 minutes.

According to the IG: "As of December 2007[1], no fire-endurance tests have been conducted to qualify Hemyc as an NRC-approved 1-hour or 3-hour fire barrier for installation at [nuclear power plants]." Thus, the NRC has known since 1994 that 17 U.S. reactors are relying on Hemyc for fire protection and that Hemyc

[1] See Office of Inspector General Report of January 22, 2008.

does not meet NRC standards, but has not enforced the regulations it established in 1980, as a result of the serious fire at the Browns Ferry nuclear plant in Alabama that disabled the power, control, and instrumentation cabling for all the emergency core cooling systems on Unit 1 and most of those systems on Unit 2. The regulations included requirements that cabling for primary and backup safety systems (a) be physically separated by at least 20 feet horizontally, or (b) be protected by a one-hour or three-hour fire barrier to lessen the risk that a single fire disables all emergency systems.

However, the NRC's own assessments of its regulatory meltdowns also repeatedly conclude that the majority of problems stem from inadequate enforcement of adequate regulations as is shown in contentions 5 through 11B

For example, the NRC lessons-learned task force examined the regulatory failures associated with the near-accident at Davis-Besse in 2002[2], and made 49 recommendations for actions the NRC should take to prevent recurrences. Forty-six of these outlined ways to improve enforcement of existing regulations, while the remaining three dealt with upgrading the underlying regulations. The NRC's

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[2] http://www.nrc.gov/reactors/operating/ops-experience/vessel-head-degradation/lessons-learned/lltf-report.html (last visited 2.15.08) According to the NRC, Davis-Besse came closer to an accident than any reactor since Three Mile Island. A crack formed in a metal tube entering the reactor vessel's lid and leaked borated water onto the carbon steel. The boric acid residue ate completely through the 6-inch carbon steel vessel to expose a one-quarter-inch stainless steel cladding applied to the vessel's inner surface. The timeline spanned an estimated six years and provided numerous opportunities for the NRC to step in. In the last missed opportunity, NRC staff drafted an order requiring Davis-Besse to shut down immediately on the basis that the reactor failed to satisfy four of the agency's five safety criteria and probably did not meet the fifth. But NRC's senior managers shelved the draft order because it would have cost the company too much money and instead waited to inspect the reactor for several months until it had a scheduled shutdown for refueling

lessons-learned efforts for Indian Point[3] provide similar findings--the regulations were in the past not the problem, enforcement is[4]. Finally compliance by Entergy to the regulations is clearly the consequence.

The licensees together with inadequate enforcement have caused significant safety and economic problems to community. In its September 2006 report, "Walking a Nuclear Tightrope: Unlearned Lessons of Year-plus Reactor Outages," UCS described the 36 times since 1966 that U.S. nuclear power reactors remained shut down a year or longer to restore safety levels eroded by accumulated violations. In these cases, more than a year, and cost an average of nearly $1.7 billion, to bring the reactor back into compliance. On February 22, 1993 Unit 3 was shutdown for over two years to attempt to restore safety levels and was not restarted until July 2, 1995. The magnitude of non-compliance and the consequential costs as well as the risks to the public are unacceptable. Unit 2 was shutdown from February 15, 2000 until January 4, 2001 (slightly less than one full year) over a steam generator tube rupture. This design basis accident is considered one of the most serious DBA's considered in the design, licensing and safe operation of the plant.

[3] As well as Millstone (Connecticut), South Texas Project, and other troubled nuclear plants
[4] However, this is now changing. See for example, proposed rulemaking regarding thermal shock http://www.nrc.gov/about-nrc/regulatory/rulemaking/proposed-rules.html (last visited 2/15/08).

Inadequate compliance by the Applicant, as well as inadequate enforcement by the NRC allowed safety levels to erode over decades for Indian Point, resulting in unnecessarily higher risk to the surrounding communities during those years and higher cost to the owners.

It also bears directly on the engineering rigor and current licensing basis compliance status as they impact contemplating an extension of 20 years post engineering design life.

Congress, UCS, GAO, IG, and NRC all identified inadequate enforcement of safety regulations as the root cause of NRC's regulatory breakdowns, and cannot be set aside during these proceedings. The Commission must consider its history with respect to Indian Point concurrently in answering to its core mandate in considering this application for renewal.

Over 140 contentions from 14 separate government or nonprofit organizations have been raised in these proceedings for admissibility. It is noted that not a single contention was accepted by the Applicant as admissible. Only about seven were recommended to be admitted by Staff. This stunningly small fraction is telling—in particular, given that the recent OIG report regarding License renewal called for substantial reform from a rubberstamping process to a process of engineering rigor, and sound regulatory oversight.

The reforms can not be deferred until after the next nuclear plant disaster using the precedent applied at NASA after Columbia, the intelligence community after 9/11, and FEMA after Katrina. The reforms will be the same; their cost will be significantly higher.

SUMMARY OF ARGUMENT

The NRC is responsible for protecting the public from the dangers inherent in nuclear power. Each regulation governing the design of nuclear power plants and any other activity authorized pursuant to the Atomic Energy Act of 1954, 42 U.S.C. §§ 2011 *et seq.* ("1954 Atomic Energy Act") must address its subject so as to minimize danger to life or property.[5] The NRC may not issue a license to a nuclear power plant unless it determines that design, operation, maintenance of the plant will adequately protect the health and safety of the public. 42 U.S.C. § 2232(a). Section 2232(a) further provides that risks to public assets are minimized.[6] The Petition brought to NRC's attention serious flaws in its current License Renewal Application. Those regulations avoid consideration of issues

[5] 42 U.S.C. §2201(i)(3)("General provisions - (i) Regulations or orders. prescribe such regulations or orders as it may deem necessary ... ***(3) to govern any activity authorized pursuant to this Act [42 USC §§ 2011 et seq.], including standards and restrictions governing the design, location, and operation of facilities used in the conduct of such activity, in order to protect health and to minimize danger to life or property."*** (emphasis added).

[6] See docketed comments, pointing out that regulations governing design of nuclear power plants must minimize danger to life and property, regarding Proposed new Subpart K—"Additional requirements" and proposed 10 Part

related to current plant operation based on the assumption that ongoing regulatory requirements ensure adequate levels of safety. This is a core issue relevant to the scope of potential safety or environmental issues relative to the renewal process in this forum.

The NRC is responsible for protecting the public from the dangers inherent in nuclear power. Each regulation governing the design of nuclear power plants and any other activity authorized pursuant to the Atomic Energy Act of 1954, 42 U.S.C. §§ 2011 *et seq.* ("1954 Atomic Energy Act") must address its subject so as to minimize danger to life or property. The NRC must consider whether the process to be performed, the operating procedures, the facility, equipment, the use of the facility, and other technical specifications provide reasonable assurance that the applicant will comply with the regulations and that the health and safety of the public will not be endangered. Sections 50.40, 50.92 (1988). The NRC may not issue a license to a nuclear power plant unless it determines that design, operation, and maintenance of the plant will adequately protect the health and safety of the public. 42 U.S.C. § 2232(a).

NRC regulations for license renewal are codified in 10 C.F.R. Part 54 and 10 C.F.R. Part 51. Petitioners brought to NRC's attention serious flaws in Entergy's License Renewal Application. Those regulations avoid consideration of issues

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52.500 "Aircraft Impact assessment" Docket No. RIN-3150-A119, submitted dated December 17, 2007, by Ulrich related to current plant operation, aging of components, and site specific impacts of the nuclear plant based on the assumption that ongoing regulatory requirements ensure adequate levels of safety. The NRC must consider whether the process to be performed, the operating procedures, the facility and equipment, the use of the facility, and other technical specifications provide reasonable assurance that the applicant will comply with the regulations and that the health and safety of the public will not be endangered. Sections 50.40, 50.92 (1988). Petitioners raise concerns of the adequacy of the environmental impact study and the aging management analysis submitted by Entergy. Petitioners also question the adequacy and ability to maintain a decommissioning fund.

Petitioners submit that a license to operate a nuclear power plant expires or terminates upon a specific a date. The NRC, upon application and thorough review, grants a new license that adheres to the rigorous standards and tests set forth for granting new licenses to operate nuclear power plants to ensure that a plant continues safely operate and adequately protects the surrounding people and environment. Petitioners contend that based on the aging of power plant, a nuclear plant that wishes to renew its license should pass the rigorous criteria set forth for operating new plants. Without these test, renewal of Indian Points operating license poses a significant safety problem.

Witte.

Entergy's license renewal application does not adhere to 10 C.F.R. Part 54. Section 54.30 requires plants to complete an Integrated Plant Assessment as part of renewal application but prohibit NRC from reviewing operational deficiencies during license renewal period. Entergy's LRA fail to consider safety concerns, environmental impacts of the nuclear power plant, continuing problems at the nuclear power plant, and review significant changes not known at the time the initial operating license was issued. Entergy did not state that a full safety review was performed.

Petitioners maintain that in light of the scientific evidence concerning the inadequacies of Hemyc, an exemption to Entergy's operating license should not have been granted during the renewal process. The NRC should also not review applications for license transfers during the renewal process either. Significant changes like these to the applicant's operating license render safety analysis meaningless.

Entergy does not have an adequate emergency plan in place and thus, its renewal license must be denied. For each plant there must be either a plan that complies with NRC's regulatory standards for responding to radiological emergencies or in the alternative, a plan that offers reasonable assurance that public health and safety will not be in danger.

The NRC fails to consider new and significant information that will have environmental impacts. Various contentions raise issues that are site specific, or should have been considered category 2 environmental impacts, and thus included in Entergy's LRA. In several instances Entergy's LRA failed to address these site specific environmental concerns.

Petitioners submit that each contention below meets the admissibility criteria under 10 C.F.R. 3.09(f) and thus, should not be dismissed.

For these contentions to reach admissibility threshold standards, the Board, must use its discretion in considering the NRC license renewal rules in the most favorable light of implementing the congressional mandate placed on the Nuclear Regulatory Commission and the Boards role in adjudicating the rule in the broad nexus to include "all issues not..." for aging nuclear plants and include all evidence regardless of current regulations sometimes unintentionally have inadequately protect the public and impermissibly restrict public and judicial review of NRC actions.

The license renewal proceedings including the application submitted for Indian Point units 2 and 3, and (further use of 55 year old systems from Unit 1) must consider the fundament fundamental nexus of unresolved current license basis issues, two 40 year old plants that were at best designed to operate for forty years, and the nexus of the legacy of operating and design failures over the past three decades in considering each of the contentions we have filed.

The NRC must consider whether the process to be performed, the operating procedures, the facility and equipment, the use of the facility, and other technical specifications provide reasonable assurance that the applicant will comply with the regulations and that the health and safety of the public will not be endangered. Sections 50.40, 50.92 (1988).

Additionally the adequacy of the decommissioning fund must be fully evaluated, light of the unremediated and unidentified leaks first discovered by an independent contractor in 2005.

Each contention put forth by Petitioners meets the admissibility criteria under 10 C.F.R. 3.09(f) and thus, should not be dismissed.

ARGUMENT

I. Petitioners have standing to intervene.

To be a party in this proceeding, Petitioners must demonstrate standing and submit at least one admissible contention within the scope of the license renewal proceedings. NRC acknowledges that Petitioners WestCAN, RCAA, and PHASE have standing to participate in this matter. (NRC brief pp.10-13). Entergy acknowledges that Petitioners all have standing to participate in this matter.

(Entergy's Answer pp. 3-15). NRC disputes the standing of Sierra Club and Richard Brodsky. (NRC brief at pp. 14-19).

In a license renewal proceeding, standing to intervene has been found to exist based on a proximity presumption. *Entergy Nuclear Generation Co. and Entergy Nuclear Operations, Inc. (Pilgrim Nuclear Power Plant Station*), LBP-06-23, 64 NRC 257, 271 (2006). The licensing Board has applied to proximity presumption to persons who reside or frequent the area within a 50 miles radius of the nuclear power plant in question. *Florida Power and Light CO (Turkey Point, Units 3 and 4)*, LBP-01-06, 53 NRC 138, 250 (2001). Petitioner Richard Brodsky, as an individual, has standing because he works approximately twenty miles from Indian Point Nuclear Power Plant. (See Declaration of Richard L. Brodsky attached hereto and made a part hereof as Exhibit A.) Accordingly, Mr. Brodsky has standing to intervene.

An organization may establish standing to intervene by demonstrating that its own organizational interests could be adversely affected by the proceeding or based on the standing of its own members. *See e.g. Consumer Energy Co. (Palisades Nuclear Power Plant),* CLI-07-18, 65 NRC 399, 409 (2007). When as organization seeks to establish "representational standing", based on standing of its members, an organization must show that as least one of its members may be affected by the proceeding, identify that member by name and address, and show that the members has authority to act on behalf of the organization. *See e.g., Consumer Energy Co., supra.* The organization member must also qualify for standing in his or her own right, the organizations interests must be germane to the organizations purpose, and neither the asserted claim or the requested relief require an individual member to participate in the organization's legal action. *Id.*

The Sierra Club-Atlantic Chapter has demonstrated standing to intervene. The Sierra Club has members who live, work, and recreate within 50 miles of Indian Point. Petitioners now attach provides that declarations of members Allegra Dengler, Joanne Steele, John Gebhards, Diana Krautter, George Klein showing that they have individual standing to intervene and have authorized the Sierra Club to represent them in this proceeding. Based on the declarations of Allegra Dengler, Joanne Steele, John Gebhards, Diana Krautter, George Klein, attached hereto as Exhibits B, SIERRA CLUB is North America's oldest, largest and most influential grassroots environmental organization. is a non-profit, member-supported, public interest organization that promotes conservation of the natural environment through public education, lobbying and grassroots advocacy. Founded in 1892, the Sierra Club Atlantic Chapter has more than 45,000 members who are residents New York States. The Atlantic Chapter applies the principles of the national Sierra Club to the environmental issues facing New York State.

The nature of the Sierra Club's interests will be adversely affected by the issuance of a renewed license for Indian Point Units 2 and 3. Thus, the Sierra Club has representational standing to intervene in this proceeding.

SIERRA CLUB is very concerned that the proposed Indian Point 2, LLC and Indian Point 3, LLC proposed 20 year superseding licenses could increase both the risk and the harmful consequences of an offsite radiological release. Furthermore, SIERRA CLUB is concerned that the radiological contamination resulting from radiological releases that would impact the and interfere with the organizations rightful ability to conduct operations in an uninterrupted and undisturbed manner. *Id.* Certainly, any evacuation would severely disrupt and damage SIERRA CLUB's operations and the residences of its membership. *Id.* SIERRA CLUB therefore qualifies for intervention pursuant to 10 C.F.R. § 2.309(d).

SIERRA CLUB also qualifies for discretionary intervention. 10 CFR § 2.309(e). SIERRA CLUB's participation may reasonably be expected to assist in developing a sound record. It is well versed in the field of nuclear energy and safety. SIERRA CLUB's constituency represents members who have participated in numerous Nuclear Regulatory Commission proceedings and public meetings. The nature of SIERRA CLUB's interests is not only its members' property interests, but the public interest. In particular SIERRA CLUB is a member of the

Indian Point Safe Energy Coalition (IPSEC), a broad coalition of 70 other free standing organizations.

SIERRA CLUB can provide local insight that cannot be provided by the Applicant or other procedural parties. SIERRA CLUB's members are Indian Point 2 and Indian Point 3's neighbors. In addition, as established in this proceeding, this proceeding may have significant affect on PHASE and its members. SIERRA CLUB therefore qualifies for discretionary intervention. 10 C.F.R. § 2.309(e). SIERRA CLUB is entitled to a full adjudicatory hearing with all the rights of discovery and cross-examination provided by 10 CFR Subpart G, because SIERRA CLUB has standing, and in the Petition herein to Intervene and Formal Request for Hearing, SIERRA CLUB raises substantial issues of fact and law that meet the requirements of 10 CFR §2.310 (d).

II. Petitioners contentions are admissible.

The NRC cannot deny a petition to intervene and request for a hearing if Petitioners demonstrate at least one admissible contention. 10 C.F.R. 2.309(a). Section 2.309(f) requires a Petitioner to set forth with particularity the contentions sough to be raised and satisfy the six criteria under section 2.309(f). "[A) petitioner must provide some sort of minimal basis indicating the potential validity of the contention." Final Rule: "Rules of Practice for Domestic Licensing

Proceedings - Procedural Changes in the Hearing Process," 54 Fed. Reg. 33, 168, 33,170 (Aug. 11, 1989). This "brief explanation" of the logical underpinnings of a contention does not require a petitioner "to provide an exhaustive list of possible bases, but simply to provide sufficient alleged factual or legal bases to support the contention." *Louisiana Energy Services,* LP. *(National Enrichment Facility)*, CLI-04-35, 60 NRC 619, 623 (2004). The brief explanation helps define the scope of a contention - "[the reach of a contention necessarily hinges upon its terms coupled with its stated bases." *Public Service Co. of New Hampshire* (Seabrook Station, Units 1 and 2), ALAB-899, 28 NRC 93, 97 (1988), aj'd *sub nomn Massachusetts v. NRC,* 924 F.2d 311 (D.C. Cir. 1991). However, it is the contention, not "bases," whose admissibility must be determined. See 10 C.F.R. § 2.309(a).

An admissible contention must (1) provide a specific statement of the legal or factual issue sought to be raised, or controverted, *provided further*, that the issue of law or fact to be raised in a request for hearing under 10 CFR 52.103(b) must be directed at demonstrating that one or more of the acceptance criteria in the combined license have not been, or will not be met, and that the specific operational consequences of nonconformance would be contrary to providing reasonable assurance of adequate protection of the public health and safety, (2) provide a brief explanation of the basis for the contention, (3) demonstrate that the issue raised is within the scope of the proceeding, (4) demonstrate that the issue raised is material to the findings the NRC must make to support the action that is involved in the proceeding; This information must include references to specific portions of the application (including the applicant's environmental report and safety report) that the petitioner disputes and the supporting reasons for each dispute, or, if the petitioner believes that the application fails to contain information on a relevant matter as required by law, the identification of each failure and the supporting reasons for the petitioner's belief, (5) provide a concise statement of the alleged facts or expert opinions, including references to specific sources and documents that support petitioners contentions, and (6) provide sufficient information to show that a genuine disputes exists with regard to a material issue of law or fact.

The standards for issuance of a renewed license are under section 10 C.F.R. 54.29(a). A renewed license may be issued by the commission as authorized by section 54.31 if the commission finds that if matters identified in (a)(1) and (a)(2) of this section, if there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB, and that any changes made to the plant's CLB are made in accordance with the Act and Commission's regulations. These matters are:

(1) managing the effects of aging during the period of extended operation on the functionality of structures and components that

have been identified to require review under section 54.21 (a)(1); and

(2) time-limited aging analysis that have been identified to require review under section 54.21(c).

See also, Nat'l Whistleblower Center v. NRC et al., 1999 WL 34833798_ (D.C.Cir. June 14, 1999).

Merits of the contention are not part of admissibility. A Licensing Board should not address the merits of a contention when determining its admissibility. *Public Service Co. of New Hampshire* (Seabrook Station, Units 1 and 2), LBP- 82-106, 16 NRC 1649, 1654 (1982), *citing Allens Creek, supra*, 11 NRC at 542; *Kansas Gas & Electric Co.* (*Wolf Creek Generating Station, Unit 1*), LBP-84-1, 19 NRC 29, 34 (1984); *Commonwealth Edison Co. (Braidwood Nuclear Power Station, Units 1 and 2*), LBP-85-11, 21 NRC 609, 617 (1985), rev'd and remanded on other grounds, CLI-86-8, 23 NRC 241 (1986); *Carolina Power and Light Co. and North Carolina Eastern Municipal Power agency (Shearon Harris Nuclear Power Plant*), ALAB-837, 23 NRC 525, 541 (1986); *Texas Utilities Electric Co. (Comanche Peak Steam Electric Station, Unit 1*), ALAB-868, 25 NRC 912, 933 (1987); *Vermont Yankee Nuclear Power Corp. (Vermont Yankee Nuclear Power Station*), LBP-88-26, 28 NRC 440, 446 (1988), reconsidered on other grounds, LBP-89-6, 29 NRC 127 (1989), rev'd on other grounds, ALAB-919, 30 NRC 29

(1989), vacated in part on other grounds and remanded, CLI-90-4, 31 NRC 333 (1990), request for clarification, ALAB-938, 32 NRC 154 (1990), clarified, CLI-90-7, 32 NRC 129 (1990); *Sierra Club v. NRC*, 862 F.2d 222, 228 (9th Cir. 1988). *See Consumers Power Co. (Midland Plant, Units 1 and 2*), LBP- 84-20, 19 NRC 1285, 1292 (1984), *citing Allens Creek, supra, 11 NRC 542; Alabama Power Co. (Joseph M. Farley Nuclear Plant, Units 1 and 2*), ALAB-182, 7 AEC 210, 216 (1974), rev'd on other grounds, CLI-74-12, 7 AEC 203 (1974); *Duquesne Light Co. (Beaver Valley Power Station, Unit 1),* ALAB-109, 6 AEC 243, 244-45 (1973). An intervenor need only state the reasons for its concern. *Seabrook, supra, citing Allens Creek, supra.*

Contention 1: Co-mingling three dockets, and three DPR licenses under a single application is in violation of C.F.R. Rules, specifically 10 CFR 54.17 (d), as well as, Federal Rules for Civil Procedure rule 11(b).

Entergy asserts that Petitioners first contention lacks specificity, factual or legal foundation, is beyond the scope of the renewal process, and immaterial. (Entergy brief pp. 38-41). The NRC staff assert that there are no applicable legal requirements that require a single application. (NRC brief at p. 34). Entergy, in support of its argument, cites to instances where commingling of licenses has occurred. (Id.)

The co-mingling three dockets and three DPR licenses under a single application violates of C.F.R. Rules, specifically 10 CFR 54.17 (d), as well as, Federal Rules for Civil Procedure rule 11(b), as explained in the Petition.

The recent Office of the Inspector General report found fault with the process and directly found the Staff reviews to be inadequate reviews of many of the previous applications submitted. Careful examination of this application shows that it can be distinguished from the non-precedent and unchallenged commingling of license renewal applications previously processed by the Staff, and approved by the Commission. Entergy's renewal applications as well as the proceedings are uniquely complex. Petitioners reiterate the uniqueness and challenge Entergy to find a similar example of: (a) the complexity of crediting a retired unit in Safestor, for Unit 2 but in a different manner for Unit 3; (b) the Architect Engineers for the two units were different; (c) the codes and standards were used to construct the two facilities were fundamentally different, and are prima facie challenges to renewal in these proceedings; (d) the owners of the facilities changed twice and therefore responses to the profusely evolved license basis requirements are unique; (e) the mandate of the commission to minimize risk to the public assets is uniquely critical given the location of Indian Point, and proximity of the world financial center within 30 miles of the plant, and the millions of people that reside within the 50 mile proximity of the plant. Each of those millions of residents could have representational standing under these proceedings.[7]

Because of independent license amendments to the extension of portions of unit 1 systems, and proper examination of the decommissioning of the remainder of Unit 1 of Indian Point, and the distinct License Renewal Application for Indian Point Unit 3, separate license renewal applications should have been submitted.

Therefore, a separate license renewal application should required be submitted for each unit at Indian Point.

CONTENTION # 2: The NRC routinely violates § 51.101(b) in allowing changes to the operating license be done concurrently with the renewal proceedings.

Petitioners contend that during the renewal process, the NRC in compliance with section 51.101(b), should not entertain: (1) requests for transfer of a license, (3) license amendments or modifications, and (3) rule making change of thermal shock. These changes to Entergy's operating license permit Entergy to renew an operating license that does not meet current standards.

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[7] In determining whether a petitioner has met the requirements for establishing standing, the Commission has directed us to "construe the petition in favor of the petitioner." *Georgia Institute of Technology* (Georgia Tech Research Reactor, Atlanta, Georgia), CLI-95-12, 42 NRC 111, 115 (1995). To this end, in proceedings involving nuclear power reactors, the Commission has recognized a proximity presumption, whereby a petitioner is presumed to have standing to intervene without the need to specifically plead injury, causation, and redressability if the petitioner lives within 50 miles of the nuclear power reactor. 10 C.F.R. § 2.309(d)(2)(i)-(ii).

The NRC Staff oppose admissibility of this contention on the basis that operating license modifications are outside the scope of license renewal. However, if an operating license that fails to meet current standards, it should not be renewed. Furthermore, a modified license, whether through a legitimate modification or exemption, changes the license to be renewed. Since the operating license to be renewed is alter, the LRA should be supplemented. Any exemption or modification will altered aging management analysis, and thus, the amended, modified or exempted license condition should be examined during the license renewal proceeding.

Petitioners' third example is particular and specific. Both the NRC Staff and Petitioner experts found significant technical errors in the TLAA most recently submitted by Entergy for Vermont Yankee, providing at least the inference of a nexus between renewal at Indian point and the proposed rulemaking that softens the regulatory requirement.[8]

Thermal shock to reactor internals directly related to TLAA[9]. The Indian Point LRA provided by the Entergy for thermal shock analysis on either Unit 2 or Unit 3 does not provide sufficient information other than a vague reference that appropriate fatigue analysis must be done under NUREG 1801 Revision 1 of the

[8] The rulemaking surrounding modification to the thermal shock rule regarding reactor internals as published in the federal register, "Notice of Proposed Rulemaking published by the NRC on October 3,2007, regarding contemplated revisions to 10 C.F.R. § 50.61.

GALL report. Therefore, the contention should be admitted because it falls within scope.

Entergy maintains that extensive use of the argument that "programmatic" environmental impact work is in progress. Under NRC regulations "while work on a required program environmental impact statement is in progress the Commission will not take ... significant action... that may affect the quality of the human environment." In order for the action not to be halted, three conditions must be met.

In the alternative, the NRC should stop all program related environmental impact statements currently in progress or contemplated during the relicensing proceedings that impact the quality of human environment—or suspend license proceedings until all program level environmental analysis is complete. Without this, the rulemaking petition is clearly inadequate.

The new thermal shock rule relieves the Applicant from stringent criteria with regard to inspection of reactor vessel internals such as baffle bolts required for safe operation of the plant. The new rule relaxes criteria for inspection of components, such as these baffle bolts, which are normally replaced after routine inspections and are replaced due to a number of environmental factors including aging. Thereby reducing unacceptably reducing the margin of safety. This

[9] The NRC is currently holding back the SER for Vermont Yankee license renewal on this very issue.

Contention including the material dispute of sufficient margin of safety for reactor vessel internal, such as baffle bolts, is an in scope license renewal components. Therefore under 10 CFR 51.101(b) the regulator cannot change the rule in while license renewal proceedings are in progress.

Thus, Contention 2 is material, particular, and within scope to be admitted.

CONTENTION 3: The NRC violated its own regulations §51.101(b) by accepting a single License Renewal Application made by the following parties: Entergy Nuclear Indian Point 2, LLC ("IP2 LLC") Entergy Nuclear Indian Point 3, LLC (" IP3 LLC"), and Entergy Nuclear Operations, LLC. (Entergy Nuclear Operations), some of which do not have a direct relationship with the license.

Both Entergy and the NRC Staff argue that this contention is not within the scope of a license renewal proceeding. (NRC Staff brief at pp. 37-38); (Entergy brief at pp. 47-51). Furthermore, Entergy responds that this contention is beyond the scope of this proceeding, lacks factual or expert support, and fails under 10 C.F.R. 2.309(f)(1(v) and (vi), and fails to identify any material deficiencies in the licensing renewal application. (Entergy brief at p. 47-51). Petitioners maintain that the NRC license renewal procedure is inadequate because it permits Entergy to apply for a transfer its operating license while a review of renewing the operating license occurs in violation of 10 CFR 51.01 (b).

Entergy's request for the indirect transfer of the Facility Operating Licenses for Indian Point 2 and Indian Point 3 be denied because the transfer violates 10 C.F.R. Part 50; violates 10 C.F.R. 54.35 and 54.37; the intended purpose of the corporate restructure is not met and is unclear; the restructuring potentially violates 10 C.F.R. 50.33(f)(2); the application fails to submit sufficient information concerning the financial qualifications of the proposed shell corporation that is not an electrical utility and the financial adequacy of decommissioning funding; and the transfer violates anti-trust laws. Despite Entergy's claim that financial issues "have no place in this proceeding" the financial viability is relevant to whether Entergy license to operate should be renewed. If Entergy's license is renewed and Entergy fails to make safety related repairs or pay decommissioning expenditures or pay retroactive Price Anderson Act premiums, Entergy cannot give reasonable assurances of health and safety of the public.

Any license transfer during a LRA proceeding brings into scope Entergy's financial qualification review to continue operating the license during the license renewal period. The proposed corporate restructure will affect the financial responsibility and liabilities of Indian Point 1,2, and 3. The proposed restructuring draws question as to whether Entergy can provide reasonable assurances of health and safety of the public. Serious doubts exist as to whether the NRC can hold a parent company responsible for the liabilities incurred by a subsidiary. Therefore, the owner and its financial status are relevant to the license renewal process to protect the public's health and safety.

The timing of this transfer application creates the opportunity for the NRC staff to do less than an adequate review, as was found by the General Accounting Office in previous reviews performed. (Exhibit C GAO Report to Congress 02-48 dated December 3, 2001). The General Accounting Office has found that the NRC has done an inadequate analysis regarding the fiscal responsibility during license transfers in the past, affecting commitments or lack thereof, including but not limited to such items as the decommissioning funds, specifically relevant to Unit 2 and Unit 3 license renewal. The General Accounting Office found that "NRC did not obtain the same degree of financial assurance in the case of one merger that created a new generating company that is now responsible for owning, operating, and decommissioning the largest fleet of nuclear plants in the United States. The new owner did not provide, and NRC did not request, guaranteed additional sources of revenue above the market sale of its electricity, as other new owners had. Moreover, the NRC did not document its review of the financial information—including revenue projections, which were inaccurate—that the new owner submitted to justify its qualifications to safely own and operate 16 plants." (GAO Report to Congress 02-48 dated December 3, 2001).

Based on the foregoing and the GAO report, the NRC license renewal procedure is defective because it permits a licensee to transfer its operating license during the pending license renewal process

Thus, Contention 3 is material, particular, raises an issue of law, and therefore is admissible.

CONTENTION 4: The exemption granted by the NRC on October 4, 2007 reducing Fire Protection standards are Indian Point 3 are a violation of §51.101(b), and does not adequately protect public health and safety.

Entergy and the NRC Staff contend that the fire standard exemption granted to licensee is outside renewal scope. (Entergy brief pp. 51-54); (NRC Staff brief at pp 38-39). As noted in the NRC Staff brief, the exemption has become part of the CLB. Furthermore, Entergy has failed to submit expert rebuttal of our expert witness declaration, and therefore their answers are without merit.

Petitioners contend that the NRC exemption granted by the NRC reducing the fire protection standards for Indian Point Unit 3 violates 10 C.F.R. 51.101(b) and does not protect the public health and safety. Under 10 C.F.R. 54.4 "[a]ll systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 C.F.R. 50.48), environmental qualification (10 C.F.R. 50.49), pressurized thermal shock (10 C.F.R. 50.61), anticipated transients without scram (10 C.F.R. 50.62), and station blackout (10 C.F.R. 50.63)." This clearly includes exemptions to federal law that are specifically mentioned under code for license renewal.

Subsequent to Entergy's LRA being accepted by the Staff, the application proposed an exemption that substantially modified the in- progress exemption regarding fire protection of power cables and control cables in the electrical cable tunnels. These new requests were done without proper notice in the Federal Register, and constituted a change in Attachment D to Appendix E of Entergy's LRA.

The exemption modified the Core Damage Frequency calculations as demonstrated in Petitioners contention 5. The exemption permits Entergy to operate although the Units have a 24-minute rated fire barrier for ETN-4, and 30-minute rated fire barrier for PAB-2, in lieu of a 1-hour rated barrier. The result of these new changes that were expeditiously approved under an apparently rushed Safety Evaluation are based upon unsubstantiated analysis, and fly in the face of 2005 EPact, as well as existing rule increasing risk to the health and safety to the public without the most modest analysis as required under 10 C.F.R.50.12.

As demonstrated in contention 5, the issue is particular, and relevant to renewal given the Entergy relies on manual actions suppress a fire in a zone that is difficult and dangerous to enter during a fire, and is a prerequisite zone to remain operational for associated systems safe shutdown analysis (ASSD).

In a series of letters dated July 24, 2006, and supplemental letters dated April 30, May 23, and August 16, 2007, responding to the NRC staff's request for additional information, Entergy submitted a request for revision of existing exemptions for the Upper and Lower Electrical Tunnels (Fire Area ETN-4, Fire Zones 7A and 60A, (respectively), and the Upper Penetration Area (Fire Area ETN-4, Fire Zone 73A), to the extent that 24-minute rated fire barriers are used to protect redundant safe-shutdown trains located in the above fire areas in lieu of the previously approved 1-hour rated fire barriers per the January 7, 1987 Safety evaluation For the 41" Elevation CCW Pump Area (Fire Area PAB-2, Fire Zone 1) ENO is requesting a revision of the existing exemptions to the extent that a 30-minute rated fire barrier is provided to protect redundant safe shutdown trains located in the same fire area.

Pursuant to 10 C.F.R. 50.12, the Commission may, upon application by any interested person or upon its own initiative, grant exemptions from the requirements of 10 C.F.R. Part 50 when (1) the exemptions are authorized by law, *will not present an undue risk to public health or safety, and are consistent with the common defense and security*; and (2) when special circumstances are present. (emphasis added). One of these special circumstances, described in 10 C.F.R.

50.12(a)(2)(ii), is that the application of the regulation is not necessary to achieve the underlying purpose of the rule.

In this case the NRC has failed to enforce its own regulations. The underlying purpose of Subsection III.G.2 of 10 C.F.R. 50, Appendix R, is to ensure that one of the redundant trains necessary to achieve and maintain hot shutdown conditions remains free of fire damage in the event of a fire. The provisions of III.G.2.c through the use of a 1-hour fire barrier with fire detectors and an automatic fire suppression system is one acceptable way to comply with this fire protection requirement. The NRC must consider whether the process to be performed, the operating procedures, the facility and equipment, the use of the facility, and other technical specifications provide reasonable assurance that the applicant will comply with the regulations and that the health and safety of the public will not be endangered. Sections 50.40, 50.92 (1988).

Contentions identifying and referring to particular documents or studies are sufficiently specific for the purpose of admission. *Sierra Club v. U.S. Nuclear Regulatory Com'n*, 862 F.2d 222 (9th Cir. 1988)(Sierra Club submitted with its contention a copy of the BNL report and made clear title in the title and text of its contention that it wished to litigate issues contained in that report was held sufficient although the contention itself did not contain any specific accident scenario, the BNL report, which was attached to the Sierra's Club contention, more than adequately identified such scenarios). The relevant inquiry is whether the contention adequately notifies the other parties of the issues to be litigated; whether it improperly invokes the hearing process by raising non-justiciable issues, such as the propriety of statutory requirements or agency regulation; and whether it raises issues that are appropriate for litigation in the particular proceeding. *Sierra Club, supra.*

Therefore, the exemption granted by the NRC, which will be carried over into the proposed license period fails to protect the health and safety of the public and does not provide an adequate aging management plan for this in scope system. Therefore Contention 4 additionally raises significant issues of fact and law regarding safety concerns and aging management that should must be admitted and heard.

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.

Petitioners assert that the fire protection exemption granted to Entergy fails to adequately protect the health and safety of the public and fails to meet to the requirements of 10 C.F.R. 50 and Appendix R.

The NRC Staff oppose this contention because it is outside the scope of the license renewal proceedings. (NRC brief at p.40). Entergy asserts that this contention does not raise a factual or legal matter and is not within the scope of the license renewal process. However, As noted in the NRC Staff brief, the exemption has become part of the CLB. Moreover, neither Entergy nor the NRC Staff have submitted expert rebuttal of Petitioners expert witness declarations and therefore their arguments are baseless. Petitioners maintain that this contention meets the six part test for admissibility. The fire standard exemption granted to Entergy does protect the health and safety of the public.

Petitioners' Contention 5 raises a factual and legal issue. NRC's standards for licenses state that the use of the facility and the facility itself must not endanger the health and safety of the public. 10 C.F.R. 50.40(a). Issuance of a license must not "be inimical to the common defense and security or to the health and safety of the public." Section 50.40(c). The fire standard exemption granted is inimical to the common defense and security or to the health and safety of the public. Petitioners question whether the Indian Point Units can safely operate.

The Fire Protection exemption is without question within scope as required under § 2.309(f)(iii). The contention raises a particular and material issue the application containing contradictory, incomplete, and evolving core damage frequency analysis regarding the probability of a fire (even disregarding the nature of the incendiary cause and (excluding a saboteur for example) the contention meets the threshold of admissibility. See § 2.309(f)(iv), in to the license basis that was available, and the pertinent sections of Appendix E to the LRA[10] provides within Attachment D, analysis methodology and results suggesting that the specific area in question i.e. the electric cable tunnels described in specificity below, contain a CDF (core damage frequency) sufficiently low[11] so as to not be listed as major core damage frequency initiators.

However, the list that provides the Probalistic Safety Analysis model Core Damage Frequency (these are results by each of the Entergy's opinion as to what are the major initiators) is absent of these tunnels but includes less likely initiators. The list which includes loss of non-essential service water, transients, station blackout, and others all have probabilities that are *greater than* the Entergy own calculation for CDF in the tunnels. This discrepancy *notably* precedes the Entergy then revising the physical characteristics of the tunnel components itself with a reduction from one hour to 24 minutes of burn time prior to cable failure and loss of emergency core cooling systems power and control running in close proximity in those fire areas.

[10] This examination does not include substantial changes to the LICENSING RENEWAL APPLICATEGORYION submitted on about December 18, that may alter this contention—however, WestCANs petition was submitted prior to December 18, and no notification was made in the Federal Register regarding a substantial revision to the Application's LRA. See motion for stay of renewal proceedings until publication of the December 18th amendment, and a public comment period.

The contention disputes genuine material facts as clarified above. The compilation of law violated as provided on pages 40 through 44 of the petition stand. Entergy's erroneously stated that Petitioner failed to establish a regulatory linkage between 10 C.F.R.50.48 and 10 C.F.R.73. One has only to look at the words plainly in 10 C.F.R.50.12: "alternatives for the exemption...must be grounded in meaningful and not superficial examination...including measures impacting the "common defense and security..." This was not done for the existing, analysis, and failure to provide adequate analysis , invalidates statements in the LRA regarding of fire protection. It is the cornerstone of the core damage frequency analysis provided in Entergy's above cited reports.

Broken current programs that are within scope and that are to credited during the new license period, including this Fire Protection exemptions, raise significant issue of fact and law. Thus Contention 5 must be admitted and heard by the ASLB.

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.

Entergy and the NRC Staff submit that contention 6 is not admissible because it is not within scope. (NRC Staff brief at pp. 40-42); (Entergy brief at pp. 55-56). Petitioners maintains that contention 6 meets the six part test for admissibility. Current law supersedes scope limitations by the Commission regarding exclusion of design basis threat as part of license renewal. Design Basis Threat (hereinafter "DBT"), while excluded by the Commission as part of License Renewal process, current precedence in the Ninth Circuit provides that fire intentionally set must be considered a required element of relicensing.

Entergy's LRA fails to address this issue. The Commission regulation codified on March 12, 2007[12] is applicable. Moreover, Entergy has not submitted expert rebuttal of our expert witness declarations and therefore their answer is without basis

Therefore, Contention 6 raises material issues of fact and law regarding aging management of Indian Point 2 and 3, is within scope, and should be admitted.

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

The NRC Staff contend that this contention fails to satisfy 10 C.F.R. 2.309(f)(1)(v)-(vi). (NRC Staff brief at p. 43). Petitioners need only state the reasons for its concern. *Seabrook, supra, citing Allens Creek, supra.* Petitioners refer to various studies and reports in their exhibits, and this have provided sufficient facts in support of contention 7.

The response provided by Entergy misses the issue entirely. Core Damage Frequency analysis provided in attachment D, to Appendix E of the LRA excludes fire incendiary sources beyond a limited scope. Under Contention 5, a CDF of 7.14E-07 per reactor year. If one assumes fire ignition and fuel is available via aircraft crashes, the entire set of models for PRA regarding fire needs revision. The plant specific IPEE excluded any "transportation accident" on the basis that would not lead to a core melt frequency of greater than 1.0E-06 per reactor year. This value is *more* frequent then about half of those listed in table 3.1-2 in Attachment D to Appendix E. None of the models[13] examined included accidental aircraft crashes as an ignition entry point into the model. Examination of industry surveys of aircraft crashes in the region surrounding the plant provide extensive evidence that fires from aircraft accident are far from remote (Exhibit D).

Second, the recent rulemaking petition drafted by the NRC, §52.500 "Aircraft Impact Assessment", raises questions regarding the mandate of the agency to minimize risk to the public assets including threats of aircraft triggered fires. Petitioners question why the NRC would codify the most modest protection for 8 plants that may never be constructed, and yet set aside protection of the

[12] 72 Fed. Reg. 12705.
[13] FIVE analysis, DBT methodology,

public health and safety for the existing 104 plants, and in particular Indian Point Plant being considered for an additional 20 year extension[14].

Finally, the following precedence provides that CDF for fire related events has a much broader uncertainty then claimed via credit under such methods as "Monte Carlo" or others. All one has to do is look at the actual record of fires at this plant, and the frequency input can be shown as invalid. A brief summary is provided in Attachment 1. Domestic fire frequency is about 1 per 100 reactors per year. Indian Point Unit 3 only recently had a fire in a transformer. A good test to the uncertainty is to correlate the actual fire frequency, multiplied to core damage threat, to those predicted. They do not correlate.

Petitioners are not challenging the rule—Petitioners are challenging the enforcement of 10C.F.R.54 to cover not to exclude, just wind, tornado, and seismic on faulted premise. Excluding these phenomena based upon incomplete PRA is questionable analysis, and appears yield a clear error in table in Appendix E.

Finally, Petitioners question how Entergy can conclude that its fire protection program as required by 10 C.F.R.54.4 is sufficient, when the existing CLB does not include compliance to the DESIGN BASIS THREAT rule—and compliance to the rule is in a state of flux. Further, Entergy has not submitted

[14] Petition filed December 17th for example.

expert rebuttal of our expert witness declarations and therefore their answer is without basis

Thus, Contention #7 is material, particular, and within scope and thuis admissible.

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

In contention 8, Petitioners contend that the NRC improperly granted Entergy's modified exemption allowing a reduction of the fire standards, while deferring necessary design modifications. The rationale is identical as in Contention 6. NRC's standards for licenses state that the use of the facility and the facility itself must not endanger the health and safety of the public. 10 C.F.R. 50.40(a). Issuance of a license must not "be inimical to the common defense and security or to the health and safety of the public." Section 50.40(c). The fire standard exemption granted is inimical to the common defense and security or to the health and safety of the public. Petitioners question whether the Indian Point Units can safely operate Here, careful examination indicates that the Entergy is failing to meet its current licensing basis pro tem—and must rely on hourly fire watches.

Numerous other discrepancies add to the uncertainty. For example, the 480 volt EDG output is unique requires different cable sizing, different heat dissipation, and additional analysis to show circuit integrity through the event. Under 10 C.F.R.10.12(c) an alternative analysis of simply replacing the hemyc wrap was not presented. There is no test data or analysis examined or the configuration qualified. Petitioners question why the cost benefit analysis performed could not support upgrading the firewrap to a 1 hour rating.

"Indian point Unit 3 Case study" provides an abundant history of distinct fire related events at Indian Point 3. Included are 20% of the fire dampers were found to fail due to improper installation, cable tunnel separation criteria failed to meet separation requirements, , design regarding lighting for fire related remote shutdown. There are 11 more all significant.

Further, Entergy has not submitted expert rebuttal of our expert witness declarations and therefore their answer is without basis, Thus this contention is material, particular, and within scope to be admitted and heard.

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.

Entergy and the NRC Staff argue that contention 9 is not within scope of a renewal proceeding. Petitioners maintain that the exemption granted by NRC granting the use of HemyC thereby reducing the fire protection standard to 24 minutes at Indian Point 3 from the standard of one hour, is carried into the new license period. (NRC Staff brief at p. 45); (Entergy brief at pp. 57-58). In fact the exemption, though omitted from the LRA, will be continued during the proposed new license period and therefore is within scope, as it directly impacts the aging management of the plant. By granting this exemption the NRC did not correct deficiencies in fire protection and instead reduced fire standards by relying on manual action to save essential equipment. (Pet. pp. 95-98) (Entergy brief pp. 57-58), which will impact material and particular issues directly related to the aging management of the plant.

Petitioners reassert that this contention raises specific and defined actions regarding retrofitting the plant to bring it into compliance, in order for the NRC to allow this exemption to be carried into the proposed license period. Entergy failed to include such retrofits, and failed to amend it's LRA to include this exemption- as required under 10 CFR Part 54.

Entergy has not submitted expert rebuttal of our expert witness declarations and therefore Entergy's answer is without basis. Based on the foregoing, Contention 9 is material, particular, and within scope. Therefore, contention 9 should be admitted and be heard.

CONTENTION No. 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.

Petitioners contend that the cable separation for Unit 2 is non-compliant, fails to meet the criteria for separation and for Appendix R. (Pet. at pp. 98-99). Entergy and the NRC Staff assert that Contention 10 is not admissible. (Entergy brief at pp. 58-61); (NRC Staff brief at pp. 46-47).

Petitioners assert that the electrical separation of Unit 2 at Indian Point was constructed under unapproved criteria. (Pet. at pp. 98-99). As a result, a single electric tunnel houses both safety related trains within approximately 12 inches of each other, which violates general design criteria and does not comply with Appendix R criteria. (Id.) Entergy's LRA fails to present adequate and lawful design measures to provide a reasonable assurance to protect the health and safety of the public; therefore, the aging program in Entergy's LRA is meaningless. (Id.)

As discussed earlier, the merits of the contention are not part of admissibility. See e.g., *Public Service Co. of New Hampshire* (Seabrook Station, Units 1 and 2), *supra*. Petitioners need only state the reasons for its concern. *Seabrook, supra, citing Allens Creek, supra*. Consequently, Petitioners have met the criteria under 10 C.F.R. 2. 309(f).

Entergy further states that Indian Point Units 2 and 3 construction permits were issued on October 14, 1966, and August 13, 1969, respectively and thus, the

General design criteria does not apply to those plants. (Entergy's brief at p. 59). This is a substantial error. The NRR Office Instruction No. LIC 100, Licensing Basis for Operating Reactors has no legal basis. There are numerous places in the license basis where the Entergy does either directly or by inference state that it intends to comply with the GDC in question.

"The Indian Point 2 (P2) Control Room Ventilation System (CRVS) meets the applicable General Design Criteria (GDC). Indian Point 2 was initially licensed based on the proposed GDCs issued for comment by the Atomic Energy Commission on July 11, 1967. Since that time, the NRC issued a Confirmatory Order on February 11, 1980, which included a requirement to conduct a study regarding compliance with the regulations of 10 CFR 50. The study performed in response to this Order included a review of the GDCs contained in Appendix A of 10 CFR 50. The results of this study were reported in Reference 1 and NRC acceptance of this response was provided in Reference 2. The applicability of the GDCs to P2 is also described in the Updated Final Safety Analysis Report (Reference 3). (See Exhibit G. p. 10).

Under the admissibility criteria of Section 2.309(f)(1), this contention is admissible. Petitioners have provided a specific statement of the legal or factual issue sought to be raised --- that the cable separation for unit 2 is non-compliant. Petitioners have provided a brief explanation of the basis for the contention – the cable separation violates GDC. Petitioners have raised an issue within the scope of the proceeding because it involves the GDC's and aging management. Petitioners have demonstrated that the issue is material and stated that it was not referenced in the LRA; thus, Petitioners could not cite to specific portions of the application. Petitioners have provide sufficient information to show that a genuine disputes exists with regard to a material issue of law or fact. (Pet. at p. 98).

Moreover, Entergy and the NRC Staff have not submitted expert rebuttal of Petitioners expert witness declarations, and therefore, the answers are without basis As a result, Contention 10 should be admitted and heard.

CONTENTION No. 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 11A asserts that the fire protection program described on page B-47 of Appendix B of the LRA does not include fire wrap or cable insulation in its aging management program. (Pet. at. pp. 99- 101). Without maintaining minimum criteria for age management of fire wraps, beyond visual inspections, the actual scope of fire barrier/insulation supplied in the application is insufficient. The NRC Staff concedes that the portion of this contention relating to the fire protection aging management program is admissible. (NRC Staff brief at p. 47).

The specific elements noted in tables provided by the Entergy are vague, incomplete, and without substance. There exists ambiguity between insulation with the word "none" inserted for aging management. In other one word entries on the table 3.5.2-4, there is simply a reference to fire protection, but no aging management program described.

Therefore, the fire protection aging management program submitted by Entergy is insufficient and thus Petitioners contention 11A must be admitted.

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.

Petitioners argue that Entergy failed to assess the increased risk of fire damage due to degraded cable insulation and thus, Entergy's LRA and the safety evaluation supporting the SAMA are incomplete and inaccurate. SAMA issues are material issues of fact that should be considered during this license renewal proceeding. Furthermore, neither Entergy nor the NRC Staff have submitted expert rebuttal of Petitioners expert witness declarations, as such, their answers should not be considered. Since contention 11A is material, particular, and within scope, the contention should be admitted and subject to a hearing.

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 deny license renewal.

Entergy argues that contention 12 is not within scope of the renewal process. THE NRC Staff argue that Petitioners failed to identify an error or omission in the application. (NRC Staff brief at pp. 49-50). Petitioners maintain that the current license basis is within scope, and must be available for a petitioner during the period allowed by rule 2.336 for intervention. Petitioners have a legal right to the pertinent parts of the licensing basis. 10 C.F.R.2.309 Moreover, under 10 C.F.R. §§ 54.19 and 54.21(c), Entergy failed to provide a comprehensive list of plant-specific exemptions, as noted by the NRC Staff. (NRC Staff brief at p. 50). Therefore, Entergy's LRA currently is not in compliance with NRC regulations.

Under section 2.309(f)(1)(iv) of the Code of Federal Regulations, the contention is material to the findings the NRC must make to support the action that is involved in the proceeding. An issue is only "material" if "the resolution of the dispute would make a difference in the outcome of the licensing proceeding." 54 Fed. Reg. at 33,172. This means that there must be some link between the claimed error or omission regarding the proposed licensing action and the NRC's role in protecting public health and safety or the environment. Dominion Nuclear Connecticut, Inc. (Millstone Nuclear Power Station, Units 2 and 3), LBP-04-15, 60 NRC 81, 89 (2004), *aff'd* CLI-04-36, 60 NRC 631 (2004).

Finally, the CLB is not a "term of art" as described by the Entergy. The CLB is precisely defined in §54.3. Even if Petitioners acknowledge the amorphous nature of the CLB and the dynamic state—Entergy is required under the rules to have the pertinent elements and they don't. This is another example that is relevant is the stunning oversight by Entergy -- their repeated statements in their reply [to contentions 10, 11B and others] that Entergy(s) for the plants are not bound to the GDC's. By them even making that statement, Entergy is attempting to change the CLB.

Entergy argues that the ASLB should "not be expected to sift unaided through large swaths" of exhibits. Petitioners argue that Petitioners should not be expected to sift unaided through 40 years of exemptions, deviations, exceptions to piece together the current CLB. Applicant's have an obligation to provide both Petitioners/Stakeholders and the ASLB a CLB that is not a vague idea, but a concrete written document A complete and non-vague CLB is the very basis by which Petitioners and the ASLB can evaluate whether the aging management of components, systems, and structures are adequately addressed in the LRA. Entergy did not provide a complete and accurate CLB to adequately assess the aging management program.

Entergy does not challenge the in-scope status of this contention. Thus, 10 pursuant to C.F.R. 2.309(f)(1)(vi), contention 12 must be admitted.

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."

The contention is admissible under the six part test. The Applicants are required to provide a complete application as required under the standards promulgated within §54.29, Entergy has failed to do so because the commitments are made in the LRA that contain language that are void under contract law. The very essence and scope of aging management programs is based on the commitments made in the LRA, the voidable nature of such commitments is clearly with in scope of the relicensing proceedings. Petitioners are particular, or specific as to where the application is incomplete.

Petitioners need not argue the merits, just show the absence of information is relevant to a few of our contentions. A properly pled contention must contain "sufficient information to show that a genuine dispute exists with the applicant/licensee on a material issue of law or fact." 10 C.F.R. § 2.309(f)(1). Although a petitioner must demonstrate that a "genuine dispute exists" at the contention admissibility stage, it need not demonstrate that it will prevail on the merits. *See* 54 Fed. Reg. at 33,170-71. Similarly, "at the contention filing stage the factual support necessary to show that a genuine dispute exists need not be in affidavit or formal evidentiary form and need not be of the quality necessary to withstand a summary disposition motion." Id. at 33,171.

On page 71 of the Applicant's response there are a number of statements regarding commitments that are completely incorrect. Licensee commitments can number in the thousands. Only a fraction have legal enforceability. The remainder are not tracked as commitments, and generally not maintained. The precise set of ongoing or onetime commitments that are docketed and in affect must be maintained by the applicant and is required by §54.3(a).

Petitioners assert that anything that is currently capable of being described in sufficient detail should be. Programs for aging management, *by contract law* can be precisely articulated—the Applicant proffers no rationale for delaying disclosure. Examples of the Applicant's failure of full disclosure include Flow Accelerated Corrosion[15], Equipment qualification[16], buried piping[17], and in

[15] For Flow Accelerated Corrosion, simply referring to an approved program such as NSAC 202L Rev 2 is not specific. There are examples of plants were they credit EPRIs industry accepted program, but fail to adequately implement it. Inspection frequency is not specified, but a critical parameter. Actual program scope, inspection frequency, grid selection, and corrective action to identified pipe thinning is not described. This leaves is public in the dark. Aging of piant piping will lead to numerous unforeseen accident scenarios if not carefully managed. No one predicted that a pipe rupture of an 18 inch line in 1986 first led to four immediate fatalities, then, loss of fire protection controls, and spurious activation of numerous electrically controlled devices included dumping of entire CO2 fire protection systems, inoperability of security doors, locking workers into rooms without immediate means to escape, and finally, threatened the safety of reactor operators when CO2 drifted or leaked into the unit 2 control room. The causal events where not predicted nor predicable. The risk and PRA associated with this event is being debated after 21 years.

[16] See contention 27.

[17] See contention 35

particular, the undisclosed refurbishment plan for the reactor heads[18]. (See Exhibit E, OIG Report, and Exhibit F, Declaration of Ulrich Witte).

By avoiding the issues, the Applicant avoids the Environmental Reporting. And thereby avoid, intervention, and foreclose the opportunity for the public to be heard and made aware of the risks.

In response the NRC Staff state that Petitioners contention is "vague, lacks expert support, fails to specify portion of the application with which it disagrees, and fails to state an admissible issue." (NRC Staff brief at pp. 51-52). Entergy claims that this contention is not supported by facts or expert opinion, fails to raise a genuine dispute on a material issue of law or fact, and impermissibly challenges 10 C.F.R. Parts 50 and 54. (Entergy brief at pp. 70-71).

Petitioners contention is that Entergy's LRA is incomplete; therefore, it cannot point to specific portion of the LRA with which it disagrees because the entire LRA is incomplete. The applicant is required to include all information in its LRA and thus the burden of proof is on the applicant to show that the LRA is complete. Since the application is required to address all EE&D's being carried over into the new licensing period, the LRA is complete if it does not include a plan for aging management of the plants degradation and fails to provide AMP's.

Therefore contention 13 must be admitted and heard.

[18] See contention xx reactor head replacement.

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."

Petitioners point to numerous material inadequacies found in the Entergy submittal. (Pet. at pp. 112-113). Entergy insists that LR-ISG-2006-03 is included in their LRA at 2.1-21, (Entergy's brief at 72-73), whereas the NRC Staff argue that contention 14 lacks specificity and basis. (NRC Staff brief at p. 53).

Essentially, the inherent weaknesses found throughout the submittal would have been at least partly avoided had they followed this guidance. Second, the guidance whether draft of final is immaterial – a point apparently considered important in the response by the Entergy. Plants were built to *draft* GDCs in 1967. That is better than no GDCs at all, which is what Entergy now is actually claiming in responses to our contention 10, 11B, and 22-25.

The date LR-ISG-2006-03 was finalized is immaterial. The NRC notes that it intends to roll this guide into NUREG 1555. This action gives it more strength – and more compelling that it be used. But there are others that are in existence and yet only one guideline was cited—and only in general terms. The licensee appears to have cherry picked the guidance at best. Where it pointed to NEI such as NEI-05-01, the Entergy used the resource to limit the extent it believed would be necessary for applying regulations to SAMA submittal. This is flawed. SAMA vulnerability (for example due to a large pipe break coolant accident) is incomplete—given that consideration is not made for steam generators that are less than 100% functional. By following the guidance—for example, LR-ISG-2006-02, "Staff guidance for environmental reports for license renewal applications" (published as a draft document in February, 2007) the following flaws would have also been avoided.

A list of the inadequacies, as compared to several EIS scoping documents submitted on October 12, 2007 is provided in Exhibit H. "Incomplete Scoping under IGS-2006-02 Guidance."

Contention 14 meets the admissibility criteria. Entergy does not challenge the in-scope nature of this Contentions. Contention 14 raises a genuine dispute with the Applicant on materials issues of law or fact as per 10 C.F.R. 2.309(f)(1) and must be admitted.

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, etc.

Petitioners maintain that this Contention meets the 6 part test for admissibility. Petitioners maintain that under NRC regulations, when the LRA is approved, the old operating license terminates and a new superseding license is issued pursuant to 10 C.F.R. 54.31. (Pet. at p. 155). Consequently, before a new operating license can be issued, the NRC must assess the nuclear power plant and its location under the same criteria as an application for a new operating license. (Pet. at p. 116).

License Renewal (as codified in 10C.F.R.54 and 10C.F.R.51) can be simplified to address four things—and four things only: (a) Aging of the plant structures, systems, and components will be sufficiently managed – where one cannot argue they are already addressed within the current license basis; (b) review of time limited aging evaluations; (c) environmental impact analysis that is clearly plant specific and not generic, (for example, severe accident risk is out of scope but alternatives to severe accidents are in scope; (d) anything else that one can prove is only possible during the renewal period but not during the current license period. (10 C.F.R. 54.21(b)).

"A contention about a matter not covered by a specific rule need only allege that the matter poses a significant safety problem. That would be enough to raise an issue under the general requirement for operating licenses (10 C.F.R. § 50.57(a)(3)) for finding of reasonable assurance of operation without endangering the health and safety of the public." *Duke Power Co. (Catawba Nuclear Station, Units 1 and 2)*, LBP-82-116, 16 NRC 1937, 1946 (1982).

As numerous agencies[19] and states[20] have asserted, as well as the Office Of The Inspector General[21], the current application bypasses a plethora of issues that start

[19] NYS petition, letter signed by six state attorneys general,

from current unresolved problems and are expected (by engineering rigor and not mere speculation) to either not be resolved at the end of the current license period, or more importantly, reflect a failed implementation of design criteria, operational criteria; or design basis accident mitigation that actually worsen by extending the operating license.

Examples that meet these criteria include:

1. Probable water contamination, with the announced intention to use the Hudson River as a source of drinking water...water.
2. Changes to the environment that are forthcoming. Weather systems, river water level and flow rates, and temperatures,
3. Probabilistic assessments of sabotage, action: cite report that shows likelihood of attack etc—and that it is likely to increase further.
4. Whether operating Indian Point for 50% longer creates new and different failure modes—as yet unpredicted but real. For example, the casual affect of the pipe break at Surry, and the consequences were entirely unpredicted,

[20] Letter dated October 24, 2007 for the EPA requesting criteria consistent with a new operating license be applied.
[21] September report

and outside the design basis accident that the plant was designed, engineered, and operated to withstand.

5. Design Basis Threat

6. The added cost of decommissioning the site with 20 *more* years of additional soil contamination, water contamination, and airborne contamination—where the Entergy has shown itself to be the nation's worst operator[22].

Finally, the material condition of the plant is critical, which depends heavily on how the plant was designed, operated, modified, and maintained compliant. For instance, the efficacy of the physical plant through the past 45 years since construction needs to be provable by the docketed record including compliance to the historical and current license bases by the Entergy. Compliance to the rules and case law by themselves must establish the sufficiency of the license bases record so as to adequately implement the congressional enacted statutes governing the protection of the health and safety of the public, as well as minimizing risk to the public assets. In contention after contention Petitioners show (along with the NEW YORK STATE Attorney Generals Office Petition) wholesale violation of the rules. One does not need to look any further than Entergy's response: "Indian Point is not required to comply with the GDC's stated regarding our petition and

[22] Reference coming... Indian Point is the dirtiest plant in the domestic fleet.

stated to other petitioners. A clear example of what lies ahead of the risks of the public assets, and the protection of the health and safety of the public.

The Entergy relies heavily on the GALL report to support their suggestion that the LRA provided is complete and compliant to law. The GALL report is guidance- not law. The question of law raised in this contention is precisely how does the Entergy interpret and apply the rules as codified in 10 C.F.R.54 and 10 C.F.R.51 so as to actually meet congressional statutory authority as prescribed the Atomic Energy Act, together with the following statutory authority[23]. This contention turns on resolution of the ambiguities.

Petitioner contend that without a superseding license by these particular facts and law, the matter not covered by a specific rule but by the particular and specific conditions found, does allege that the renewal of Indian Point poses a significant safety problem. Because there is no definition listed in for "license renewal" or "relicensing" in the NRC regulations, Petitioners reason that the criteria for obtaining a initial operating license are just as applicable for relicensing. Alternatively, the aging management analysis covers the same review that is necessary for obtaining a renewed license.

Thus, contention 15 should be admitted.

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 16 urges the NRC to consider the site specific conditions at Indian Point and perform an updated seismic analysis. Indian Point is right on top of two major earthquake belts that intersect and each is approximately twenty feet wide. Since Entergy's LRA failed to include a seismic analysis, the NRC should order Entergy to do so. In reply, Entergy argues that this issue is beyond the scope of this proceeding, immaterial to license renewal, the contention lacks factual or expert support, and fails to show a genuine dispute exists. (Entergy brief at pp. 77-79). The NRC Staff also state that this issue is beyond the scope of license renewal. (NRC Staff brief at pp. 58-60).

Contention 16 raises the issue of whether a seismic analysis, a site-specific environmental issue relating to Indian Point, should be required before a new operating license is approved. Petitioners Argue that an analysis should be conducted because there are site specific considerations removing seismic analysis from a category one environmental issue to a category two issue. Petitioners need only state the reasons for its concerns. *Seabrook, supra, citing Allens Creek, supra.* Due to the site specific conditions of Indian point a seismic analysis should be conducted because it is a category 2 environmental issue.

Petitioners explain several severe consequences if an earthquake were to occur, particularly in light of the aging equipment. Under 10 C.F.R.54.21, the licensee must evaluate the aging of the plant structures, systems, and components will be sufficiently managed, where not addressed in the current license basis, and perform an environmental impact analysis that is clearly plant specific and not generic. Entergy's LRA does not.

The issues raised in contention 16 are particular and specific. (Pet. at p. 134). For example, ISFI issues were admitted in recent precedence[24].

Once Petitioner is admitted as a party, Petition will seek a waiver to compel reanalysis of Class 1 piping, and Class 2 piping.

This could be accomplished while saving the Entergy substantial costs in the generally overly conservative seismic analysis performed in the late 1970's and early 1980's. It is likely, that snubbers can be removed, and substantial costs of maintaining or replacing those snubbers be avoided. Given that the plant is required to maintain a complete design record, including the "asbuilt" configuration of each facility, specifically including piping schematics and isometrics. It is also possible to show that the existing analysis is conservative against the revised seismic OBE and SSE criteria. If on the other hand, the analysis is non-conservative, and the Entergy is aware, and chooses not to disclose

[24] Pet. at p. 10, contention 6

configurations that are currently do not meet design basis accident requirements. Then other enforcement rules come into play, and Entergy has a compliance issue much bigger than Seismic analysis of safety related systems components and structures.

The engineering requirements including thermohydraulic fatigue analysis is specifically required under §54. There is significant ASME code case relief available since 1978, for example Code Case N-597, and others. However, given Entergy's position that it is not bound by any GDCs associated with pipe stress etc, this contention provides another example of the incomplete LRA. How can one prove adequate engineering management of aging and degradation of class 1 piping, when, the Entergy states that it is not bound to the GDCs?

The aging management of the systems, components and structures are within scope and therefore an updated seismology report should be required. This contention raises material issue of fact and law which are in dispute and therefore should be admitted and heard.

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.

Entergy and the NRC Staff argue that the population density issue is outside the scope of renewal proceedings. (Entergy brief at p. 79-81); (NRC Staff brief at p. 61). Entergy failed to address increased population density surrounding Indian Point[25] in their inadequate environmental report.

For the reasons stated in contention 16, the population density surrounding Indian Point is site specific and should be heard. NEPA empowers the NRC to require an environmental study of the environmental impact of a proposed action if the action would significantly affect the quality of the human environment. 42 U.S.C. 4332(2)(C). A license renewal application is a significant and major event under the NEPA. The applicant's environmental report must include "any new and significant information regarding the environmental impacts of license renewal of which the applicant is aware." 10 C.F.R. 51.53(c)(3)(iv). Changes in factual and legal circumstances may impose upon an agency obligation to reconsider a settled policy or explain its failure to do so. *Bechtel v. FCC*, 957 F.2d 873, 881 (D.C.Cir. 1992); *AHPA v. Lyng*, 812 F.2d 1 (D.C. Cir. 1987).As stated in Petitioners contention 17, Indian Point is surrounded by one of the most densely populated areas in the U.S. and 21 million people live within 50 miles of Indian Point. (Pet.

at. p. 140-142). Entergy responds that changes in population density do not require reassessment because this issue is not in the scope of 10 C.F.R. Part 54.

Petitioners need only state the reasons for its concerns. *Seabrook, supra, citing Allens Creek, supra.* The increasing population density surrounding Indian Point, as explained in contention 17, is new and significant information that should have been addressed in Entergy's environmental report. The dense population is an issue that is site specific and should be evaluated in accordance with 10 C.F.R. Part 100. Because this issue is site specific and known to Entergy, it should be included in its environmental report as a category two issue. Contention 17 should be admitted and heard because it raises genuine material issues of fact and law that are dispute.

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.

Entergy and the NRC Staff state that this issue is outside of the scope of the aging management considerations relative to license renewals. (Entergy brief at p. 81).; (NRC Staff brief at p. 62). Again, for the reasons stated in contention 16, contention 18 raises a site specific issue and thus should be admitted. Entergy's

[25] There is a 1982 study that shows Indian point property values within the 50 mile zone as being by far the highest of any of the 104 operating plants in the country. In 1982 dollars it was of the order of 400 billion.

failure to adopt an adequate emergency and evacuation plan does not protect the health and safety of the public. Entergy's emergency and evacuation plans have held inadequate by the James Lee Witt and Associated Report commissioned by Governor Pataki of New York, and endorsed by Congressional leadership including Hillary Clinton, Edward Markey and Bernie Sanders.

Furthermore, Entergy's non-working sirens is an aging management issue.

The failure of Entergy to install a functional siren system mandated by Congress is clear evidence, that Entergy inadequate management of emergency and evacuation systems and emergency plans hindered by limited roads and increased traffic. (Pet. at p. 142). The LRA does not address how Entergy will adequately manage the aging evacuation and emergency systems during the proposed new license period. The site specific issues, at Indian Point with regard to Emergency Planning must be fully evaluated as Category 2 issues, including the inability for Indian Point install sirens with backup power, as required by Congressional law. Entergy attempts to claim that this contention is outside the scope of the aging-management matter considered in license renewal proceedings. (Entergy brief at 81). Entergy cites to *Millstone*, CLI-05-24, 62 NRC at 560-561 in which the Board stated that "emergency planning is, by its very nature, neither germane to age related degradation nor unique to the period covered by [a] license renewal application." (Entergy brief at p. 81-82).

However, the very mandate of the NRC is to adequately protect the public. Without a functional evacuation plan Indian Point cannot continue to operate for an additional 20 years. Thus contention 18 should be admitted.

CONTENTION: 19 Security Plans Petitioners 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 C.F.R. 100.12(f) and 10 C.F.R. 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.

Along the same lines as Contention 16-18, contention 19 raises questions about the adequacy of Entergy's security plans at Indian Point. (Pet. at. 149-157). Entergy and the NRC Staff respond that security plans are outside the scope of license renewal proceedings citing to *Vermont Yankee*, LBP-06-20, 64 NRC at 172-173. (Entergy brief at 82-83); (NRC brief at p. 63-64).

In accordance with 10 C.F.R. 2.309(f)(3) and *Consolidated Edison Co. (Indian Point, Units 2 & 3)*, CLI-01-19, 54 NRC 109, 132 (2001), where both Petitioners independently established standing, the Presiding Office has the discretion to permit Petitioners to adopt the others' contention early in the proceeding. Petitioners join and adopt contention of parties raising this same issue.

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

Entergy claims that the issues raised in contention 20 are outside the scope of license renewals. (Entergy brief at pp. 83-84). Petitioners reassert that the very mandate of the NRC is not adequately protect the public. However, Applicant's LRA is void of aging management plans to address systematic failures as evidence by many issues, including, but not limited to, the radioactive leaks, deficiencies in emergency planning, boric acid corrosion of the vessel heads for both Unit 2 and 3, steam generator issues, impending failure of the steel containment plate.

The very mandate of the NRC is to adequately protect the public. The LRA does not address how Entergy will prevent adequately protect the public functional evacuation plan Indian Point cannot continue to operate for an additional 20 years. Thus, Contention 20 raises materials issues of fact and law that are in dispute as per 10 CFR 2.309(f)(l) (vi) must be heard and omitted. Precedents on point supporting the admissibility of this Contention include the following:

- *Louisiana Energy Services, L.P.,* CLI-05-20 (2005)- Petitioner was seeking review of Atomic Safety and licensing board decision on environmental uranium disposal- held board should admit it for a hearing

- *Exelon Generation Co., LLC*, CLI-05-17 (2005) – mandatory hearings under 10 C.F.R. 103, 1046 of AEA (42 U.S.C. 2239(a)

The very mandate of the NRC is to adequately protect the public. The LRA does not address how Entergy will prevent adequately protect the public functional evacuation plan Indian Point cannot continue to operate for an additional 20 years.

The NRC Staff contend that "[*m]ost* of the issues that the Petitioners bring up have nothing to do with the GEIS or the Supplemental to the GEIS." (emphasis added) (NRC brief at p. 66). The NRC Staff also state that Petitioners have failed to seek a waiver of the regulations. Under the NRC regulations, only a party can seek a waiver of a regulation. Until at least one contention is admitted, a Petitioner is not a party. Thus, once Petitioners are parties, we will seek waiver of the issues that should be considered as category 2 environmental issues.

Thus contention 20 should be admitted.

Contention 21 was omitted from the Petition.

Contentions 22-25

The regulatory rules for obtaining a new superseding license, as delineated in the code of federal regulations, specifically riles under 10 C.F.R. Part 54, License Renewal, and 10 C.F.R. Part 51, Aging Management, were set aside by the Application in lieu of suggested criteria promulgated by the trade industry. The Applicant misrepresented the specific General Design Criteria which formed the basis of the Safety Evaluation Report granting the Unit 2 operating license and subsequently remained in violation of the terms of its operating license and with the federal rules for four decades. Therefore the Applicant placed economics before the health and safety of the public.

The Applicant, as well the federal agency, willfully and knowingly violated the Administrative Procedures Act, and as a result, now has prostituted the license renewal application for Indian Point Unit 2. The aging Management Programs proposed by the Applicant are based upon misrepresentations of the actual general design criteria to which Indian Point Unit 2 was license. The as-built construction of the facility does not comply with the safety evaluation report, the operating license or to the code of federal regulations.

The U. S. Nuclear Regulatory Commission (NRC) is currently assessing the need to review the 41 older nuclear power plant units referred to as the Systematic Evaluation Program Phase III (SEP-III) plants. Generic Safety Issue (GSI) 156-6.1 (R. Emrit, et al., 1993) deals with whether the effects of pipe break inside containment have been adequately addressed in these plants' designs. The NRC originally evaluated a majority of the SEP-III plants before they issued Regulatory Guide (RG) 1.46 in May 1973 (AEC, 1973b). Although the NRC reviewed these plants, there is a potential lack of uniformity in those reviews due to the absence of documented acceptance criteria. The NRC is now attempting to assess the impact of not having such criteria in place.

The extent of the violations are breathtaking, and involve a substantial prima facie breach of Administrative Procedures Act (APA) by the Federal Agencies over almost four decades for Indian Point 2. Beginning in 1968, the Nuclear Regulatory Commission acted in direct defiance of the Administrative Procedures Act by approving Amendment Nine of the Operating License, (contained in exhibit I) in which the Licensee acknowledged commitments to *trade comments* to draft General Design Criteria for its new plant. In addition, the Licensee committed to trade comments to the proposed General Design Criteria, and erroneously claimed that the trade organization comments were published in the Federal Register for public comment in July, 1967, when in fact they were never properly published. (See Exhibit U).

The Licensee claimed adherence to a General Design Criteria required for the licensing of Indian Point 2 facility, and committed to such General Design Criteria in the 1970 SER. In actuality, the plant design, programs and procedures *were licensed to trade industry-endorsed commentary* as opposed to the General Design Criteria for the LRA and subsequently approved by the Atomic Energy Commission under the 1970 Safety Evaluation Report (See Exhibit V) bypassed the federal rules as found under the rule making process. The draft GDC's were published and approved for use more than 13 months prior. This fundamental failure of oversight by the regulator was subsequently set aside and festered, while the commission quietly authorized by retroactive fiat that the licensing process proscribed under federal rules for Indian Point 2 could remain in violation of law. This series of events is evidenced by close examination of documents cited or submitted in the applicant's LRA. The commission dealt with the design basis and license failures with a stroke of a pen in 1992. (See Exhibit W).

The table below best provides the chronology as well as the facts, and the implications to the renewal license application fidelity. In simplest terms the Licensee and NRC with the acceptance of the GDC defined in Amendment 9 to the original application for license accepted a draft industry GDC in place of the actual GDC for IP2. Table 1 Timeline of proposed trade design criteria and misrepresented as conforming to federal law:

Date:	Docketed Activity	Reference	Implications to fidelity of the License Amendment
November 22, 1965	Early draft General Design Criteria published by AEC for comment	November 22, 1965 Press release from AEC. No FR notice	For consideration by Con Ed in decision to Construct Indian Point 2
October 14,1966	By application dated December 6, 1965, and amendments thereto (the original application), the applicant applied for the necessary licenses to construct and operate a nuclear power reactor at the applicant's site at Indian Point, Village of Buchanan, Westchester County, New York.	The Commission, after a public hearing and after an initial decision by the Atomic Safety and Licensing Board (the Board), established by the Commission, issued Construction Permit CPPR-21 for this facility	The application was evaluated by the Commission's regulatory staff and independent Advisory Committee on Reactor Safeguards (ACRS), both of which concluded that there was reasonable assurance that the facility could be operated at the proposed site without undue risk to the health and safety of the public. On October 14,1966,
July 11, 1967	AEC publishes draft General Design Criteria under federal rule making processes.	Federal Register 32 FR 10213	Note that the draft GDCs were never made a part of Appendix A of 10CFR50.
October 2, 1967	Atomic Industry Forum, a trade organization, provides significant comments regarding draft GDCs published.	Provided directly to Atomic Energy Commission without publication in the federal register	AIF general proposed removal of conservatism in draft General Design Criteria. **These changes were never approved by the AEC.**
October 15, 1968	Former owner of Unit 2 submits Amendment 9 of application of license	AEC Docket No. 50-247-- correspondence from Con Ed to Director of Division of Reactor Licensing Atomic Energy Commission	Facility that was now more than 2 years into construction was being constructed following unapproved trade documents – however, the letter states on page 1.3-1 that the unapproved "general design criteria tabulated explicitly in this report comprised of the proposed AIF versions of the criteria issued for comment in July 1967."
February 1970		See January 28, 1971 NRC discussion of AIF GDC comments.	The staff met with an ad hoc AIF group, which included representatives of reactor manufacturers, utilities and architect engineers to discuss the revised General Design Criteria. The comments of this group were reflected in a June 4, 1970 draft of the revised General Design

Date:	Docketed Activity	Reference	Implications to fidelity of the License Amendment
			Criteria that was forwarded to the AIF for comment. The AIF forwarded comments and stated it believed the criteria should be published as an effective rule after reflecting its comments. These comments have been reflected in the GDC in Appendix "A".
November 16,1970	Safety Evaluation Report Commission grants operating license based upon amendments 9-25 of application for license by Con Edison.	Incorporated License amendments 9-25 to the application and the FFDSAR -includes ALSB, ACRS review et al.	"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. This document gave them authority to operate the facility under the draft GDCs but **without the AIF comments specifically for the** Reactor Protection and Control System. As noted, "Specifically, for 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

Date:	Docketed Activity	Reference	Implications to fidelity of the License Amendment
			reviewed extensively in the past and we conclude that the design for Indian Point 2 is acceptable".
February 20 1971 through July 11 1971	Formerly Draft GDCs are approved Final GDCs and become part of Appendix A to 10 CFR 50. They are amended the same year.	Published in FR. on February 20 1971, and amended on July 11, 1971	These are the first legal standards for which the plant is required to comply or under federal rules, or be granted an exemption.
November 4, 1971	A third modified construction permit was issued for Units #1 and #2. The proposed relocation of the intake structures by Con Edison was a significant improvement and entered into this decision.		The USAEC is urged to require Consolidated Edison to establish a firm schedule for implementing this proposed modification because of changes in the design of the adjustable discharge ports and slide gates.
September 28, 1973	Unit 2 Operating License Received		SER states that the plant is licensed to 1967 draft general design criteria **without endorsement of AIF comments.**
Commission issues a confirmatory order on February 11, 1980	Unit 2 FSAR dated June 2001 states that the detailed results of the order indicate that the plant is in compliance with the then current General Design Criteria established in 10CFR50 Appendix A.		The commission concurred on January 1982.
September 18, 1992	SECY 92-223, "resolutions of deviations identified during the systematic evaluation program"	Letter to James Taylor, Executive Director for Operations	The Commission approved the staff proposal in which **the plant was not required to comply with federally approved General Design Criteria, if construction permits were issued prior to May 2, 1971.** **This is a clear and flagrant violation of the Administrative Procedures Act.**

Date:	Docketed Activity	Reference	Implications to fidelity of the License Amendment
June 2001	Unit 2 FSAR states incorrectly that the General Design Criteria tabulated explicitly in the pertinent systems comprised the proposed trade organization general design criteria.	Section 1.3 General Design Criteria, Unit 2 UFSAR, and indicates under a footnote that the safety analysis report added trade organization comments in the change to the FSAR. (see footnote within Section 1.3.)	The license with collateral endorsement of the federal regulatory agency bypassed the administrative rules act, and thus reduced its commitments made to obtain its operating license to less than the minimum legal requirements of 10 CFR 50 Appendix A which were made law more than two years prior to the NRC granting the applicant an operating license for Unit 2. **The reductions of safety margin and reasonable assurance of protection of the health and safety of the public have been compromised for over three decades, without the public understanding of the loss of margin in safety. Subsequently, Entergy allowed the error to remain and is actually currently committing Unit 2 to trade organization design criteria.**

Consequences of these actions: The Licensee's failure to adhere to a legally enforceable General Design Criteria substantially reduces safety margins for safe plant operation, by severely reducing detection of and the consequential mitigation of accident conditions resulting in substantial reduction in protecting the health and safety of the public.

The Nuclear Regulatory Commission continued this pattern of bypassing the Administrative Procedures Act in 1992, in which the regulator relieved the Applicant of *all compliance* enforcement to any General Design Criteria, without any attempt to abide by the Administrative Procedures Act. The Commission belief that it could use guidance documents from trade organizations in lieu of rules as was adjudicated in *Metropolitan Edison Company, et al. (Three Mile Island Nuclear Station, Unit No. 1) ("TMI")* ALAB-698, 16 NRC 1290, 1298-99 (October 22, 1982), affirming *LBP-81-59, 14 NRC 1211, 1460 (1981),* where it was established that the criteria described in NUREG-0654 were intended to serve solely as regulatory guidance, not regulatory requirements*).* Indeed, the Commission's mere reference to NUREG-0654 in a footnote to 10 C.F.R. § 50.47 was found to be insufficient to incorporate that guidance document by reference as a part of a federal regulation, even if the Commission had intended to do so.

The Nuclear Regulatory Commission continues this approach today without any hint of complying with the rules of the Administrative Procedures Act (APA). In summary, the Applicant is obligated to meet the requirements of the General Design Criteria as published on July 11, 1967. In fact, the Applicant falsely states that it is in compliance on page 3 of the LRA. Indian Point 2 LLC plant was designed, constructed and is being operated on the basis of the proposed General Design Criteria, published July 11, 1967. Construction of the plant was already underway when the Final Facility Description and Safety Analysis Report was filed on December 4, 1970, and when the Commission published its revised General Design Criteria in February 1971, and final version of the General Design

Criteria in July 1971, which included the false statement. As a result, we did not require the applicant to reanalyze the plant on the basis of the revised criteria. However, our technical review assessed the plant against the General Design Criteria now in effect and we have concluded that the plant design conforms to the intent of these newer criteria.

The Applicant was not in compliance with 10 C.F.R. 50 Appendix A then, and is not in compliance with 10 C.F.R. 50 Appendix A now, as provided in current 2006 Unit 2 UFSAR submitted as a part of its relicensing application. Subsequent to the issuance of the Operating License, the Nuclear Regulatory Commission issued many Bulletins, Orders, Generic Letters, and Regulatory Guides. Most of the Regulatory Guides address the Nuclear Regulatory Commission's interpretation of the meaning of the requirements of the 1971 General Design Criteria. Inference could be made that regardless of the legal basis of these orders, if one accepts them as legal, one must also accept the legal requirement of compliance to the specific relevant 1971 General Design Criteria. However, the process clearly violated the Administrative Procedures Act regarding the incorporation by reference on regulations such as violation of 10 C.F.R. 50.21, regarding equipment aging 10 C.F.R. 50.21 (1) Safety-related systems, structures, and components which are those relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49 (b)(1)) to ensure the following functions-- (i) The integrity of the reactor coolant pressure boundary; (ii) The capability to shut down the reactor and maintain it in a safe shutdown condition; or (iii) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in § 50.34(a)(1), § 50.67(b)(2), or § 100.11 of this chapter, as applicable. (2) All nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1)(i), (ii), or (iii) of this section. (3) All systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63). (b) The intended functions that these systems, structures, and components must be shown to fulfill in § 54.21 are those functions that are the bases for including them within the scope of license renewal as specified in paragraphs (a)(1) - (3) of this section. [60 FR 22491, May 8, 1995, as amended at 61 FR 65175, Dec. 11, 1996; 64 FR 72002, Dec. 23, 1999]

program scope by using a methodology that is entirely addressed under NUREGS prepared and promulgated outside rulemaking procedures and industry trade guidelines such as NEI 95-10 Rev. 6, each of which has no legal force. Neither public involvement nor the most fundamental steps required under the Administrative Procedures Act were adhered to by either the Applicant or the Federal Agency.

Pursuant to section 3(a)(1) of the Administrative Procedure Act, 5 U.S.C. § 552(a)(1), as implemented by the regulations of the Office of the Federal Register, 10 C.F.R. Part 51, no material may be incorporated into a rule by reference unless the agency expressly intends such a result, 10 CFR. § 51.9, requests and receives the approval of the Director of the Office of Federal Register, 10 C.F.R. §§ 51.1, 51.3, and the Federal Register notice indicates such specific approval, 10 C.F.R. § 51.9.

A brief review of statutory/regulatory construction confirms the method for incorporating Regulatory Guides. Here 10 C.F.R. Part 50, Appendix E, n.1; NRC Staff Regulatory Guide 1.101, Rev. 2 (October, 1981) specifically endorses the incorporation by reference to the criteria and recommendations in NUREG-0654 as "generally acceptable methods for complying" with the standards in 10 C.F.R. § 50.47. The NRC's emergency planning rules, however, include neither such a designation nor any express intention that NUREG-0654 be incorporated by reference.

In the absence of other evidence, adherence to NUREG-0654 may be sufficient to demonstrate compliance with the regulatory requirements of 10 CFR §

50.47(b). However, such adherence to NUREG-0654 is not required, because regulatory guides are not intended to serve as substitutes for regulations. *TMI, ALAB-698, supra, 16 NRC at 1298-99*. Methods and solutions different from those set out in the guides will be acceptable if they provide a basis for the findings requisite to the issuance or continuance of a permit or license by the Commission." *Id.* at 1299, quoting *Pacific Gas and Electric Co. (Diablo Canyon Nuclear Power Plant, Units 1 and 2), ALAB-644, 13 NRC 903, 937 (1981)*. Petitioners believe the atomic licensing board erred in this decision. This error was confirmed in the recent ruling regarding storage of spent fuel requiring a NEPA proceeding compliance prior to the NRC approval. See *San Luis Obispo Mothers v. NRC 03-74628.*

Examples include certain Regulatory Guides that provide requirements for post-accident monitoring of the TMI incident. These Regulatory Guides describe a method that the NRC staff considers acceptable for use in complying with the agency's regulations and delineate an acceptable means of meeting the General Design Criteria as contained in 10 C.F.R. 50 Appendix A. More than 100 Regulatory Guides have been issued, amplifying the requirements of the General Design Criteria. The NRC developed Regulatory Guide 1.97 to describe a method that the NRC staff considers acceptable for use in complying with the agency's regulations with respect to satisfying criteria for accident monitoring instrumentation in nuclear power plants. Specifically, the method described in this Regulatory Guide relates to General Design Criteria 13, 19, and 64, as set forth in Appendix A to Title 10, Part 50, of the Code of Federal Regulations (10 C.F.R. Part 50), —Domestic Licensing of Production and Utilization Facilities:

> Criterion 13, —Instrumentation and Control, requires operating reactor licensees to provide instrumentation to monitor variables and systems over their anticipated ranges for accident conditions as appropriate to ensure adequate safety.
>
> Criterion 19, —Control Room, requires operating reactor licensees to provide a control room from which actions can be taken to maintain the nuclear power unit in a safe condition under accident conditions, including loss-of-coolant accidents (LOCA's). In addition, operating reactor licensees must provide equipment (including the necessary instrumentation), at appropriate locations outside the control room, with a design capability for prompt hot shutdown of the reactor. Criterion 64, —Monitoring Radioactivity Releases, requires operating reactor licensees to provide the means for monitoring the reactor containment atmosphere, spaces containing components to recirculate LOCA fluids, effluent discharge paths, and the plant environs for radioactivity that may be released as a result of postulated accidents. The licensee has responded to these communications and states compliance with these communications and makes a commitment in the UFSAR.

In these examples, the Applicant included the NUREG language in the FSAR, and by inference one could argue compliance in this case with General Design Criteria 1971. The Applicant could not, however, use the Aging Management Program to argue compliance with other cases, and certainly cannot use the program exclusively. The Applicant is potentially holding open options that should be eliminated under the Aging Management Rule. (See Contention X).

A dispositive example is "General Design Criteria Criterion" 35-Emergency core cooling:

> A system to provide abundant emergency core cooling shall be provided. The system safety function shall be to transfer heat from the reactor core following any loss of reactor coolant at a rate such that (1) fuel and clad damage that could interfere with continued effective core cooling is prevented and (2) clad metal-water reaction is limited to negligible amounts. Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is available) the system safety function can be accomplished, assuming a single failure. *See* General Design Criteria 35, Final design criteria (10 C.F.R. 50 appendix A approved 1971, (36 FR 3256, Feb 20, 1971)).

The IP2 Final Safety Analysis Report (FSAR) does not address Criterion 35 at all. In neglecting to do so, the IP2 FSAR leaves the General Design Criteria meaningless in its intent to protect the health and safety of the public, and places the plant in clear violation of 10C.F.R. 50 Appendix A. A detailed list of specific violations contained within 10 C.F.R. Part 54 will be provided in supplemental submittal to this contention.

Contention 23 is an example is provided below from review of the limited material available to Petitioner by the Licensee, and the regulator.

> Criterion 10, Reactor design, in which the reactor core and associated coolant, control, and protection systems must be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences. FSAR Section 5.1.1.1.5, Reactor Containment substantiates the Criterion with the following additions:
>
> 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.*** [italics and bold added] These additions provide latitude and judgment to the Applicant as to what the Architects and Engineers need to do in order to minimally satisfy the criteria ***but do not support the right for public review of the pertinent documents in a public forum.***

A brief review of Tech Spec requirements contained in Exhibit Y confirms that the misrepresented statement in the FSAR regarding General Design Criteria for Unit 2 is followed through with improper implementation. See e.g.,, Reactor Coolant Leakage. In LCO 3.4.13, reactor containment pressure leakage from primary to secondary systems ***is allowed in quantities up to 150 gallons per day***. Such quantities are much larger than reasonable limits implicit under General Design Criterion 35. This non-conservative quantity may have contributed to the root cause of the 2000 tube rupture accident and is intolerable as an acceptable quantity for age management of the RCS leakage.

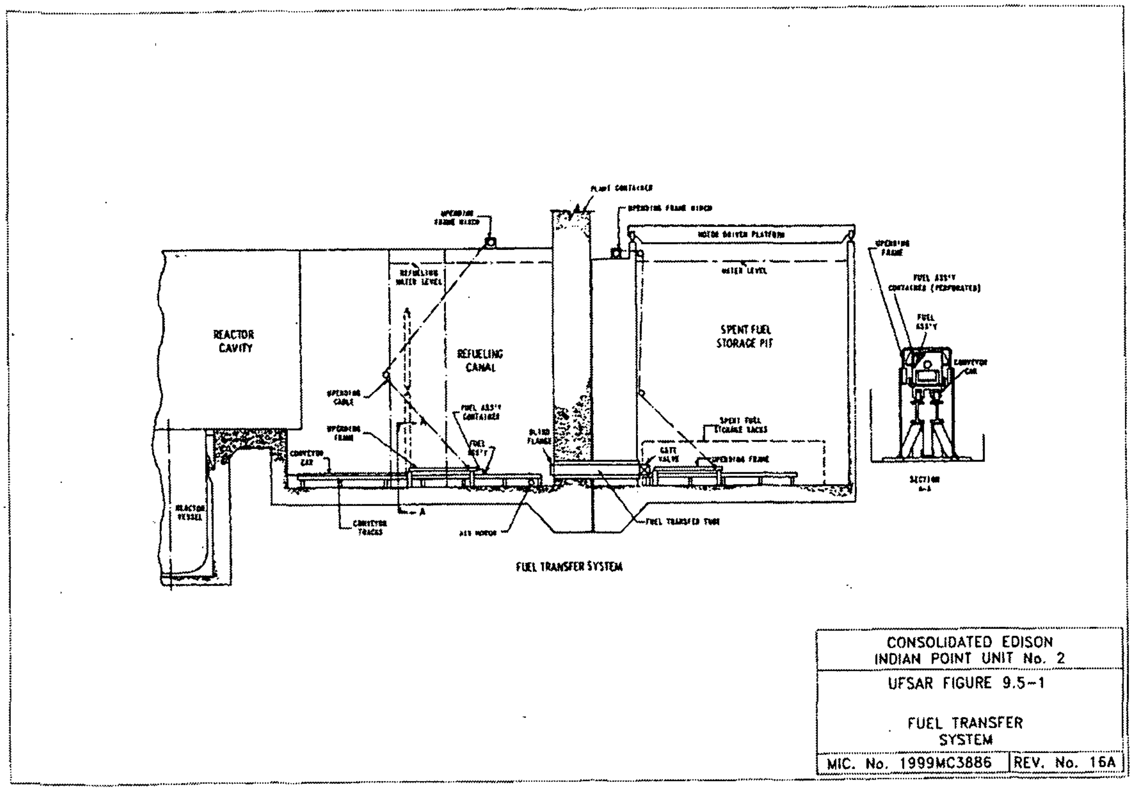
A second example may be found in examination of General Design Criterion 45, through General Design Criterion 6.2.1.2. Inspection of Emergency Core Cooling System Criterion is the following: Design provisions shall, where practical, be made to facilitate inspection of physical parts of the emergency core cooling system, including reactor vessel internals and water injection nozzles. (General Design Criteria 45). Here the trade organization inserted the words "where practical." (see Exhibit Z at page 14).

The Applicant bypasses the rules, by failing to properly examine or replace reactor core internal components with known susceptibility to failure on multiple occasions. For example, the components such as baffle bolts that hold down springs, lower core barrel, and lower core plate are routinely UT or VT'd during outages and often replaced. (See Exhibit AA).The process involves a machine that typically removes and replaces bolts in an automated procedure which adds two weeks to an outage. Despite the higher reliability of such a process, Indian Point 2 has chosen instead to rely on water chemistry tests which are meaningless for assessing bolt integrity. The reasoning behind the reliance on an inferior method of testing is financial: Water chemistry tests enable Indian Point 2 to substantially reduce lost revenue by shortening the outage time (some estimates are in the order of millions of dollars per outage day), despite the fact that the health and safety of the public is sacrificed. See exhibit P and the declaration of Ulrich Witte, Exhibit Q. This is a prima facie violation of 10 C.F.R. 50 Appendix A.

The Applicant attempts to placate the issue with the following words contained in the LRA, —to manage loss of fracture toughness, cracking, change in dimensions (void swelling), and loss of preload in vessel internal components, the site will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval. See section A.2.1.141 of the LRA report.

This language essentially removes this entire matter from the public's right of input and participation. It is another example of —Agree to agree and bypasses the procedures required by law through the Administrative Procedures Act. Alternative methods that act as proposals to comply with the federal rules for license renewal represent guidance only, unless explicitly cited, and developed within the confines of the Administrative Procedures Act. The above examples meet the standards for specific contentions as cited above.

This serious and deliberate practice of rewriting federal code without public input is in clear violation of the Administrative Procedures Act and invalidates the plans proposed for the technical, safety, and environmental aspects of entire LRA, even setting aside the issues of a lack of completeness and vagueness of the description. The misrepresentation has become routine, and the violations so acceptable, that recently was published as notice regarding a leaking and aging 20-inch pipe, described by the media as a —conduit with a pinhole leak.



Misrepresentation does violence to the entire intent of the agency, and the Applicant's failure to comply with specific rules of 10 C.F.R. 54, and further violates the Administrative Procedures Act. For example, the 20-inch —conduit is not considered part of the Aging Management Program or part of the environmental program, and the lack of inspection and maintenance of it is not considered unlawful. (See Exhibit BB).

The breadth and depth of these contentions are extreme. Even if each issue is classified in the narrow confines of the scope of the Rule (however not NEI 4.2 and not the GALL Report (but see NUREG 1801 Rev. 1) this egregious conduct by the applicant and the regulatory failure raises questions about any statement made in the LRA, or the Current Licensing Basis for Unit 2.

The Current Design Basis for Indian Point 2 and 3 are unknown, unmonitored, and the materiel condition reflecting the actual CLB therefore cannot be established. These conditions associated with the CLB were the exact bases for permanent closure of Millstone Unit 1. These findings for Indian Point 2 are clearly analogous, and a new superseding license has insufficient ground for approval. For those issues raised here, no distinct and independent forum is available to adjudicate the magnitude of the misrepresentation and unlawful acts.

The Petitioners question how a Board selected by the Commission can be allowed to judge the acts by the very Commission that selected it (such as the 1992 letter contained in Exhibit CC). The Administrative Procedures Act under chapter 5 provides for adjudication in the federal court for exactly this kind of broad unlawful act.

Finally we question statements that directly conflict with the LRA regarding legal conditions to which the Licensee/Applicant claims it complies with the GDCs. These statements are made in the LRA and its appendices repeatedly. Yet, Entergy's response to the coalition petition argues exactly the opposite, and further more in contention after contention. See Exhibit DD.

We proffer definitive prima facie documentation that shows otherwise. We provide that in Exhibit EE. That (1) LIC 100 is of no legal significance what so ever, and is nothing more that exactly its title. See Exhibit FF. An office instruction for Nuclear Reactor Regulation. Where as responses to generic letters are legally binding, and are enforceable.

The core of the both aging management and TLAA rest upon what exactly the design basis is, and that license basis as defined in §54.3 is available, and the record has integrity. We find it does not. The mandate of the Commission cannot be met without the CLB known, the GDCs conformed to the rule, and in implemented with sound engineering rigor, and then and only then, can renewal analysis have any validity.

Contention 26: Omitted from Petition.

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.

This is a dispute over material facts- not applicable law. Petitioners challenge Entergy's LRA for Indian Point Units 2 and 3 because it fails to comply with (a) 10 C.F.R. § 50.49(e)(5) & Part 54, and (b) the federal rules mandated after the Three Mile Island tragedy to protect the health and safety of the public. (Pet. at p. 187). Entergy opposes contention 27 on the basis that they claim the contention is outside the scope. (Entergy brief at p. 96). The NRC Staff state that this contention is not admissible because it "fails to identify any error or omission in the application. It is vague and unfocused, and thus fails to meet the requirements of §2.309(f)(1)(i) and (vi)...PHASE does not explain how 10 C.F.R. §50.49(e)(5) is violated, or why these assertion establish a dispute with the LRA." (NRC Staff brief at p. 71).

Although Entergy attacks credibility of Petitioner's expert witness, Mr. Witte, Entergy does not submit expert rebuttal, and therefore their allegations must not be considered. Mr. Witte's expertise is well documented in his CV.

Petitioners have met the 6 part test. Entergy responses argument regarding processes is engineering nonsense. The current EQ systems that are out of compliance, cannot be credited towards the proposed new license term. The Applicant credits a rudimentary economic analysis which concluded that a 50%

change of multiple equipment failure as acceptable. It is obviously not. The Advisory Committee on Reactor Safeguards (ACRS) found that this economic analysis evidenced a disregard of federal rules regarding Entergy's CLB, 10 C.F.R. 50.49 and 10 C.F.R. 50.4. The issue is thus within scope. Although we are not conceding that the contention as written does not meet the six part test, Exhibit I provides additional items of particularity.

Petitioners assert that the scientific methodology that was stretched to reach 40 years and cannot is inadequate to be stretched to 60 years. The Applicant's LRA has failed to address the aging effects are cumulative and issues of limited functionality and integrity of in-scope components such as Instrumentation and Control cables. Contention 27 is within scope and must be admitted.

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.

Petitioners assert that Entergy's Quality Assurance Program violates the requirements in 10 C.F.R. 50, Appendix B. (Pet. at p. 204). Specifically, Petitioners maintain that Entergy's Quality Assurance Program for Aging Management is ineffective. (Pet. at p. 204).

Entergy opposes admission of this contention because it falls outside the scope of this proceeding. (Entergy brief at p. 99). Additionally, the NRC Staff contend that Petitioners failed to demonstrate that the issues raised are material to the findings the NRC must make and that Petitioners fail to provide sufficient information that a genuine dispute exists. (NRC Staff brief at pp. 73-74).

Petitioners need only show that the Appendix B program translates to inadequate oversight and the consequences are fundamental to the operational safety of Indian Point 2 and Indian Point 3. Entergy does not assert that their Quality Assurance Program is in compliance, rather they attempt to claim that the condition or failure of the QA program should not be considered in the NRC's safety review.

Petitioners argue that a managed program for aging of equipment cannot be credit to a program that there is some nexus between the alleged omission and the protection of the health and safety of the public. *Millstone, supra*. The failed Appendix B program translates to inadequate oversight and the consequences are yet again fundamental. You can't get to a managed program for aging of equipment, when the plant has , a "broken" track record of maintenance, operational issues, corrosion, design basis accidents, have in their roots the Appendix B program that is not independent in violation of 10 C.F.R. 50 Appendix B.

Where the Entergy intends to fully credit an existing program as adequate, and it is fundamentally failing to comply with Appendix B, Petitioner and the ASLB have the right and the obligation to bring it into renewal consideration. To ignore this, creates conditions which place the public assets and their health and safety at risk. Entergy does not dispute that the Quality Control at Indian Point has been seriously reduced and that they have credited this reduced program to be carried into the proposed 20 year additional license term. Therefore the Quality Control program is within scope. Because contention 28 raises material and particular issues of fact and law in dispute, it is therefore admissible.

Contention 29: Failed Quality Assurance Program

Petitioner's Response to Contention 28 is reference and incorporated fully, as if set forth herein.

Contention 29 raises the specific failures during the second quarter of 2007, regarding an attempt to clear interference of sumps while implementing modifications to the vapor containment and recirculation pumps is an example of a cross cutting issue, were the root cause was improperly attributed and the quality assurance failure was not addressed. This failure and the methodology used that is being credit to be carried over into the proposed 20 year license period is not addressed in the LRA. The root cause of the failure of the current Quality Control program has been brought into scope. Contention raises material and particular issues of fact and law in dispute and therefore is admissible.

Contention 30

Petitioner's Response to Contention 28 is reference and incorporated fully, as if set forth herein.

Contention 30 is a second example that supports contention 28, but is its own contention. It raises a separate and distinct issue that procedure regarding temporary modifications are inadequate. This contention is unchallenged by the Applicant. It meets the six part test with specificity and particularity. Temporary modifications will be a substantial element of modifications required if the LRA is granted. A deficient temporary modification program is fatal a safe transition to license renewal.

Applicant's Appendix B program translates to inadequate oversight and the consequences are fundamental to the operational safety of Indian Point 2 and Indian Point 3. Entergy does not assert that their Quality Assurance Program is in compliance, rather they attempt to claim that the condition or failure of the QA program should not be considered in the NRC's safety review. Petitioner's argue that a managed program for aging of equipment cannot be credit to a program that has , a "broken" track record of maintenance, operational issues, corrosion, design basis accidents, that is in violation of 10 C.F.R. 50 Appendix B.

Where the Entergy intends to fully credit an existing program as adequate, and it is fundamentally failing to comply with Appendix B, Petitioner and the ASLB have the right and the obligation to bring it into renewal consideration.. To ignore this, creates conditions which place the public assets and their health and safety at risk. Entergy does not dispute that the Quality Control at Indian Point has been seriously reduced and that they have credited this reduced program to be carried into the proposed 20 year additional license term. Therefore the Quality Control program is within scope.

Contention 30 raises material and particular issues of fact and law in dispute and therefore is admissible to be heard.

Contention 31

Contention 31 is a separate and distinct contention that raises procedures regarding the failure to establish corrective actions associated with monitoring the service intake bay level. Failure of Entergy to take corrective action, without the issue being re-identified by the NRC indicates that the current configuration management and control of the facility is insufficient, yet Entergy is crediting their corrective action program for the proposed additional 20 year term. This contention is unchallenged by Entergy. It meets the six part test with specificity and particularity. Configuration management and corrective action programs are substantial systems required if the LRA is granted. A configuration management and corrective action program is fatal to an safe transition to renewal. Therefore Contention 31 raises material and particular issues of fact that are in dispute, which are admissible and should be heard.

Contention 31 raises the issue that there appears to be no configuration management control program at either facility., even though Unit 3 had a commitment to have a bona fide program in place their keys back in 1996 after being shut down for over a year, and after being on the NRC's watch list Unit 3. Based on the examples provided in Contentions 28,29, 30, and 31 Petitioners argue that the required program has become completely obliterated and broken, therefore Entergy cannot take credit for it in it's LRA. Omission of an adequate aging management configuration management control program raises material and particular issues of fact that are in dispute, which are admissible and should be heard.

The examples provided in contentions 28, 29, 30, and 31 all support the notion that if the program is there, it is broken. Therefore, contentions 28, 29, 30, and 31 should be admissible.

Contention 32: Indicators of a failed Safety Culture Work Environment

Contention 32 is a separate and distinct contention that raises serious issues with regard to the failure of safety culture assessment and confidence by workers in raising safety concerns. This contention is unchallenged by Entergy. It meets the six part test with specificity and particularity. Substantial safety work culture being credited in the LRA is a substantial element in license renewal proceedings. A deficient safety work culture is fatal to an safe transition to renewal. Therefore Contention 32 should be heard.

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 C.F.R. 51.53 post-construction environmental reports and of 10 C.F.R. 51.21.

The contention meets the six part test for admissibility in spite of Entergy's attempt to discredit the evidence. The NRC Staff "do not oppose the admission of PHASE Contention 33 for the limited purpose of verifying whether the Applicant has omitted plans to replace the reactor vessel head as a refurbishment item associated with license renewal." (NRC Staff brief p. 75).

The contention meets the six part test for admissibility in spite of Entergy's attempt to discredit the evidence. Although Entergy does not deny that a RPV head was purchased, Entergy does not deny they it may replace the heads during the 20 year license period and that will constitute major refurbishment Inspection indicated streaks of brown stains, and there are issues with upper head injection nozzles that are unique to Indian Point Westinghouse Reactors. This is a major design evolution. Extensive engineering work is required to establish integrity between an embrittled vessel barrel, and a new head.

Even if Entergy did not deliberately omit the information regarding the RPV and refurbishment contemplated during the proposed additional 20 year term, the Doosan "slide show" evidences such information should have been included in the LRA, and have not been left to be brought to the attention of the ASLB by Petitioner's discovery.

Petitioners have raised a concise statement of fact, have raised material issue of law and fact that are in dispute, and are within scope, therefore Contention 33 is admissible.

CONTENTION 34: Petitioners 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.

Petitioners contend that accidents involving the breakdown of certain equipment, parts, components, and systems are not adequately addressed in Entergy's LRA for Indian Point Units 2 and 3. (Pet. at p. 226). Specifically, Entergy's LRA fails to include aging management of the following, including but not limited to, boric acid corrosion, internal bolting, fuel rod control system, duty valve failure, briny reactor water coolant environment, cable degradation, cumulative effect of constant exposure of the reactor vessel to neutron irradiation and reduction in the fracture toughness and ductility of the PWR internal, refurbishment issues, primary water stress corrosion cracking, fatigue of metal components, heat and shell exchange replacement, accident analysis, digital upgrade of the rod control logic and power cabinets, risks of low temperature flow accelerated corrosion, industry wide problem of securing hand contingency spare parts, shortage of engineers with knowledge of pools, premature failure of containment coatings, increasing obsolescence issues of original equipment, reactor vessel issues, and cables. (Pet. at pp. 226-233). Entergy's LRA does not address certain accidents associated with breakdown of components. Based upon *Mass v. United States* precedence and the rules that the burden indicated as the petitioner's actually is out of context.

The scope meets the threshold of admissibility any of the following:

(a) Aging of the plant structures, systems, and components will be not sufficiently managed – where one cannot argue they are already sufficiently addressed within the current license basis.

(b) review of time limited aging evaluations

(c) environmental impact analysis that is clearly plant specific and not generic, (for example, severe accident risk is out of scope but alternatives to severe accidents are in scope)

(d) anything else that one can prove is only possible during the renewal period but not during the current license period.

Significantly, expert opinion on this particular topic given Mr. Witte's known expertise in configuration management which was not challenge by expert witness rebuttal.

The contention is admissible under the six part test. NRC regulations require that an applicant provide a complete application under the Section 54.29. Entergy's LRA does not address certain accidents associated with breakdown of components.

Petitioners have sufficiently pled sufficient information to show a genuine dispute. 10 C.F.R. § 2.309(f)(1). Specifically, a contention "must include references to specific portions of the application... that the petitioner disputes and the supporting reasons for each dispute, or, if the petitioner believes that the application fails to contain information on a relevant matter as required by law, the identification of each failure and the supporting reasons for the petitioner's belief." Although a petitioner must demonstrate that a "genuine dispute exists" at the contention admissibility stage, it need not demonstrate that it will prevail on the merits. *See* 54 Fed. Reg. at 33,170-71. Similarly, "at the contention filing stage the factual support necessary to show that a genuine dispute exists need not be in affidavit or formal evidentiary form and need not be of the quality necessary to withstand a summary disposition motion." *See* 54 Fed. Reg. at 33,170-71.

Entergy counters that the contention is beyond the scope of renewal proceedings and that it is not particular, or specific regarding where the application is incomplete. (Entergy brief at p. 106). The NRC Staff add that the contention is not supported. (NRC brief at p. 77).

The contention is admissible under the six part test. NRC regulations require that an applicant provide a complete application under the Section 54.29. Petitioners have sufficiently pled sufficient information to show a genuine dispute. 10 C.F.R. § 2.309(f)(1). Specifically, a contention "must include references to specific portions of the application... that the petitioner disputes and the supporting reasons for each dispute, or, if the petitioner believes that the application fails to contain information on a relevant matter as required by law, the identification of each failure and the supporting reasons for the petitioner's belief." Although a petitioner must demonstrate that a "genuine dispute exists" at the contention admissibility stage, it need not demonstrate that it will prevail on the merits. *See* 54 Fed. Reg. at 33,170-71. Similarly, "at the contention filing stage the factual support necessary to show that a genuine dispute exists need not be in affidavit or formal evidentiary form and need not be of the quality necessary to withstand a summary disposition motion." *See* 54 Fed. Reg. at 33, 170-71. The recent report provided by the Office of the Inspector General regarding deficiencies in licensing renewal proceedings support with question the substance of this contention. (Exhibit N).

Petitioners assert that anything that is currently capable of being described in sufficient detail should be. Programs for aging management, *by contract law* can be and should be precisely articulated— Entergy proffers no rationale for delaying disclosure. Examples of such programs include Flow Accelerated Corrosion[26], Equipment qualification[27], buried piping[28], and in particular, the undisclosed refurbishment plan for the reactor heads[29].

Contention 35

Withdrawn.

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[26] For Flow Accelerated Corrosion, simply referring to an approved program such as NSAC 202L Rev 2 is not specific. There are examples of plants were they credit EPRIs industry accepted program, but fail to adequately implement it. Inspection frequency is not specified, but a critical parameter. Actual program scope, inspection frequency, grid selection, and corrective action to identified pipe thinning is not described. This leaves is public in the dark. Aging of piping will lead to numerous unforeseen accident scenarios if not carefully managed. No one predicted that a pipe rupture of an 18 inch line in 1986 first led to four immediate fatalities, then, loss of fire protection controls, and spurious activation of numerous electrically controlled devices included dumping of entire CO2 fire protection systems, inoperability of security doors, locking workers into rooms without immediate means to escape, and finally, threatened the safety of reactor operators when CO2 drifted or leaked into the unit 2 control room. The causal events where not predicted nor predicable. The risk and PRA associated with this event is being debated after 21 years.

[27] See contention 27.

[28] See contention 35

Contention 36: FAC

In this contention, Petitioners claim that Entergy's program does not include an adequate plan to monitor and manage aging of plant piping due to flow-accelerated corrosion of during the extended period of operation.

Management of FAC fails to comply with 10 C.F.R. § 54.21(a)(3).205 Section 54.21(a)(3) which requires that, for each structure and component identified in Section 54.21(a)(1), the Applicant "demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation." The contention and its related basis is related upon three things. These are the program as described in the LRA, which the applicant credits as being affective and in place today, (2) the record of the so called effective program to date, and (3) expert opinion provided by Declaration on Ulrich Witte.

The issue of the efficacy of the checwork program is challenged. Efficacy can only be confirmed by actual current performance as examined its use at Indian Point. The program is designed as essentially a trending tool, and based upon trending of wear, then provides selection points for inspection of wall thinning

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[29] See contention regarding reactor head replacement.

events. Entergy has since about 2005 implemented a generic procedure (See Exhibit Q) and has not had success in this program being effective. Examples of failures of the implementation are provided in Exhibit R. We maintain that the applicant 's program is deficient because it, and there is insufficient benchmarking of the program to correlate a mechanistic examination with an empirical analysis.

In this same vein, Petitioners further claim that Entergy has failed to demonstrate "a good track record with use of CHECWORKS." We note with interest that this same program implemented another Entergy plant currently in renewal proceedings, and was not just admitted, but also denied motion for summary disposition only months ago. See Exhibit S.

We fundamentally take issue as to the contention meeting the six part test, and the facts we bring clearly show a genuine dispute with the applicant.

Finally, we note that yet again vague indescript summary of the program provided in the LRA, and that the LRA "fails to specify the method and frequency of component inspections or criteria for component repair or replacement." We assert that the program provided in the LRA leaves the petitioner forced to conclude that there Entergy has no meaningful program to address FAC aging phenomena." This content is admissible because it establishes a genuine dispute with the applicant on a material issue of law or fact, and without question raises Issues within the Scope of this Proceeding.

Finally the expert, Mr. Witte, is also the expert on the faulted identical program (See Exhibit T) scheduled for trial at Vermont Yankee this summer. Therefore, while Petitioners note the NRC Staff criticism of Mr. Witte, it should not be considered. (NRC Staff brief at pp. 85-86).

Despite Entergy's and the NRC Staff's assertion of admissibility, (Entergy brief at pp 113- 118) based on the foregoing, contention 36 is admissible.

CONTENTION 37
Withdrawn.

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

Entergy does not deny the microbial corrosion issues raised by Contention 38. The seriousness of the eyewitness account should not be ignored by the ASLB, especially in light of the recent corrosion issues with the new, yet to be installed siren system, in which the manufacture has claims that the corrosive nature of the Hudson River has caused the unexpected corrosion. Microbial corrosion was omitted from the LRA and therefore Entergy does not have an aging management program to address this during the 20 year license period.

In Contention 38 Petitioners have raised issues of fact that are in dispute and should be admitted and heard.

CONTENTION 39
Withdrawn.

CONTENTION 40

Withdrawn because it is a duplicate of Contention 14.

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

Contention 41 meets the six part test for admissibility. The passive components, structure and systems of the Interm Storage Fuel Installation (ISF) for spent fuel storage is site specific and within scope.

At Diablo Canyon, the ASLB panel acknowledged that the petitioners had submitted substantial evidence that the proposed ISFSI presents a significant safety issue, The proposed expansion of the spent fuel storage facility is inherently risky. Especially if sited in a seismically active area. Like Indian Point both the power generation and spent fuel storage facilities at Diablo Canyon present targets for cataclysmic acts of terrorism and sabotage. As such, the safety and environmental risks inherent in the proposed expansion of DCPP's spent fuel storage facility must — to the extent consistent with plant security — be evaluated carefully and publicly

Additionally Entergy has not demonstrated that it is financially able to cover the costs of constructing, operating and decommissioning the proposed ISFSI which is necessary in during the 20 year new license period, due to the additional high level radioactive waste that will be produced during that time. Therefore the environmental impacts of the ISFI are within scope, yet Entergy does not identify an aging management program to handle such impacts.

The 2,000,000 pounds of high level radioactive waste is currently maintained on site. During the proposed 20 year additional license approximately 1,000,000 pounds will be added to that, yet there a solution to disposal of this waste does not exist. This is an issue of fact that must be raised and fully adjudicated during the relicensing proceedings, as it directly impacts the aging management of the plant and the environmental impact of the site. In fact the proposed license period increases the long term waste storage by 50%. Petitioners have submitted the expert testimony of Gordon Thompson with regard to Robust Spent Fuel Storage.

The Waste Confidence Rule was written in 1995 many years prior to the contemplation of dry cask storage as the only option for increasing spent fuel. Therefore the dry cask storage is an in scope component necessary to the new license term, and therefore site specific issues caused by the new use of Indian Point cite for long term high level radioactive was storage, will be carried into the proposed new license period.

Staff claims that spent fuel storage is as a Generic issue, but Petitioners claim it is not a generic issue, but site specific and there is new evidence of large quantities of unidentified and unremiedated leaks that must be addressed in the relicensing proceedings.. The current non-compliance and failure to stop leaks will be carried over into the new superseding license period and therefore within scope.

Contentions 41 raises particular issues of law and fact that are within scope and are in dispute, and which Entergy failed to address in the LRA; thus Contention 41 is admissible and should be heard.

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 42 meets the six part test for admissibility. The passive components, structure and systems of the dry cast storage are site specific and within scope.

The Waste Confidence Rule was written in 1995 many years prior contemplation of dry cask storage as the only option for increasing spent fuel. Therefore the dry cask storage is an in scope component necessary to the new license term, and therefore site specific issues caused by the new use of Indian

Point cite for long term high level radioactive was storage, will be carried into the proposed new license period. The specificity of the need for additional dry cask storage as set forth in this Contention is based on conference with staff and is not speculation as Entergy proposed.

Once Petitioner is accepted as a party we will apply for a waiver to consider this issue as a Category 2, site specific issue.

At Diablo Canyon the ASLB panel acknowledged that the petitioners had submitted substantial evidence that the proposed ISFSI presents a significant safety issue, The proposed expansion of the spent fuel storage facility is inherently risky. Especially if sited in a seismically active area. Like Indian Point both the power generation and spent fuel storage facilities at Diablo Canyon present targets for cataclysmic acts of terrorism and sabotage. As such, the safety and environmental risks inherent in the proposed expansion of DCPP's spent fuel storage facility must — to the extent consistent with plant security — be evaluated carefully and publicly.

Additionally Entergy has not demonstrated that it is financially able to cover the costs of constructing, operating and decommissioning the proposed dry cask storage required to continue operation of the plant for an additional 20 year new license period. Therefore the environmental impacts of the dry cask storage are within scope, yet Entergy does not identify an aging management program to handle such impacts.

The 2,000,000 pounds of high level radioactive waste is currently maintained on site. During the proposed 20 year additional license approximately 1,000,000 pounds will be added, yet there no longer term solution to disposal of this waste. This is an issue of fact and law that must be raised and fully adjudicated during the relicensing proceedings, as it directly impacts the aging management of the plant and the environmental impact of the site. In fact the proposed license period increases the long term waste storage by 50%. The current dry cask pad is inadequate to hold the additional waste and yet the Applicant's LRA fails to consider this and address the aging management program for this additional waste.

Since long term and potential permanent dry cask storage was not a contemplated use of the site when it was initially sited, before this use can be credited and carried into the proposed additional 20 year license term a full review and evaluation of the site, including public comment is required. This is new information and the reality of dry cask storage on site for an unknown term brings it within scope as it is a major component that must be included and must be reviewed as site specific material issue of fact.

Contentions 42 raises particular, concise material issues of law and fact of components, and systems that are passive and necessary for the continued operation of Indian Point, which Entergy failed to address in it's LRA. Such material issues of law and fact are in dispute, thus Contention 42 is admissible and should be heard.

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.

This Contention satisfies the six part test. Entergy does not contest that in scope nature of this issue. The new information that Barnwell will no longer be accepting low- level radioactive waste from Indian Point is not addressed in the LRA, nor is an aging management program identified to handle low level waste. The Applicant's failure to include this material issue of fact in the LRA does not excuse it from being a material issue that is in dispute.

The Applicant has the obligation to submit an LRA that addresses aging management issues, to fail to address the handling of low level waste disposal for the 20 year license period at Indian Point, is evidence of the incompleteness of the LRA. The LRA is mute on this. Because the Applicant omitted low level waste management form the LRA does not prevent it from being a material issue of dispute.

The Applicant's attempt to characterize Petitioner's contention as speculative, and place in question the industry known reality that Barnwell is closing its doors to Indian Point in 2008, is evidence of the Applicant failure to provide necessary information. Low level waste management is an essential in scope systems for which a functional aging management plan is required and planned for during the superseding license period.

Since low level waste storage was not a contemplated use of the site when it was initially sited, before this use can be credited and carried into the proposed additional 20 year license term a full review and evaluation of the site, including public comment is required.

Staff's quote regarding *Ocennee* only deals with "high level waste." Low level waste management is an essential in scope systems required to be function and planned for during the superseding license period.

The LRA is mute on this. Because it is omitted from the LRA, as if it doesn't exist, or as if there was a plan to dispose of the waste does not prevent it from been a material issue of dispute. Staff does not refute the fact that Barnwell is closing and that there is no plan to dispose of the low level waste.

Therefore Contention 43 raises an issue of fact that is within, and thus, is admissible.

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.

In light of the massive underground leaks of strontium, tritium and cesium c Indian Point is one of the dirtiest sites in the country. Additionally, Indian Point is location in the middle of some of the most expensive real estate in the nation. As such, the adequacy of the decommissioning funds is a material issue and is relevant to the ASLB's approval of a 20 year license extension.

Petitioners contend that the decommissioning funds have not been adjusted to take into account the evidence of these leaks as report in the January 7, 2007 GZA report. Additionally the funds have not been recalibrated on decommissioning costs derived from 60 years of non-linear growth in contamination. The applicant does not present concrete evidence that it has adequate funds to clean up the site.

Applicant also claims that the decommissioning is not related to the extended operation of the plant. Petitioners assert Applicant's statement is short sighted and self serving, when it is an issue of fact the recalibrated decommissioning costs must be adjusted from 60 years of non-linear growth in contamination. Entergy's claim that 50.75 offers adequate monitoring and oversight of the adequacy of the decommissioning funds is refute when the calculations of the biennial reports evidence that the decommissioning funds have only been adjusted by 1% a year, rather adjusted as required to the cost of living increases at the rate of 3% a year. This short fall, extended over the 20 year proposed additional license period will cause disparity in 2035 dollars by approximately 40%, which would substantially reduce Entergy's ability to properly and fully decommission the plant. A mismanaged fund is the same as no management at all.

Entergy's position contradicts Commission's determination in prior action that WestCAN can raise adequacy of Decommissioning Fund in Relicensing proceedings. (Pet. at pp. 293) (NRC Staff brief at p. 101). This argument by Entergy is one of convenience and attempts to thwart Petitioner's ability to address a substantive issue of aging management a system necessary for the safe decommissioning of the plant. Entergy's claim that the only time to raise this is after the LRA is approved greatly reduces and limits Petitioner's right to the point of making Petitioner's concerns ineffectual. The record in CL1-00-22 is clear, that the Commission refused to hear issues of the adequacy of the decommissioning fund in the license transfer application and said that it should be raised under relicensing.

Entergy alleges that the Commission was disingenuous in making such a statement and really never meant that decommissioning could be raised under relicensing Under Entergy's assertion the Commission was only using it as a ruse to prevent Petitioners from raising the adequacy of decommissioning fund in either meaningful proceeding Petitioner's do not accept that the Commission would act in such an unjust manner, and therefore Entergy's assertion much be rejected.

The decommissioning fund is not only a current license issues, but pertains to and is carried into the superseding license period. The NRC regulations require that an adequate decommissioning fund be available prior to the issuance of a license.

Staff's position contradicts Commission's determination in prior action regarding license transfer of Indian Point 3 where it stated that WestCAN can raise adequacy of decommissioning fund during Relicensing proceedings. (P 293 of our Petition or p 101 of Staff response). This argument by Staff is one of convenience and attempts to thwart Stakeholders rights to address a substantive issue. Staff claims that the only time to raise this is after the LRA is approve is self serving and would cause Petitioner's rights to be greatly limited and made ineffectual. Decommissioning in not only a current license issue, but pertains to and is carried in to the superseding license period.

Contention 44 is pled with specificity and raises material issues disputing fact and law regarding the adequacy of the decommissioning required under 10 C.F.R. 54.3 and 10 C.F.R. 50.75 in order for approval of the proposed 20 year license.

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

This contention is within scope, and Entergy does not assert otherwise. Entergy's assertion that until the matter pending in New York with respect to Entergy's discharge permit is resolve with finality, the NRC is constrained to assess the pending LRA on the basis of the currently- permitted system, is inaccurate. NRC staff has acknowledged that without a discharge permit the NRC cannot grant a operating license to Entergy, and New York State DEC has already determined that a retrofit with close cycle cooling is required to meet EPA standards. Thus, Petitioner's assert that until the matter is resolved there is a matter of law in dispute that is specific and particular, and clearly meets the threshold of admissibility and should be heard.

Finally until the matter pending in New York with respect to Entergy's discharge permit is resolved with finality, the NRC is constrained to assess the LRA on the basis of the currently permitted system" seems dead wrong for a basis for not admitting the contention. The opposite should be argued. Until the matter is resolved we have a matter of law in dispute that is specific and particular, and clearly meets the threshold of admissible.

CONTENTION 46: Omitted

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

Entergy claims "other than unsupported speculation regarding releases in the future", however Petitioners assert that the new information regarding the projected future radiological leaks provided in the leak study by GZA for Entergy of January 7, 2008, must be incorporated into the EIS with regard to projected future leaks and the Cumulative site specific health issues.

Petitioners have cited New York State Cancer zip code studies as evidence that thyroid cancer rates in the two miles surrounding Indian Point is 70^ higher than areas further away. This is clear evidence that the health impacts of Indian

Point currently and credited into the proposed new licensing period is not small, but significant and therefore cannot be considered a Category 1 issue.

Entergy fails to challenge Petitioner expert witness, Joseph Mangano with expert rebuttal, and only cites unrelated and distinct studies. Therefore Entergy's challenge to Mr. Mangano's declaration is without basis and must be dismissed.

Once Petitioner is accepted as a party we will apply for a waiver to consider this issue as a Category 2, site specific issue.

Thus, Contention 47 raises material issues of law and fact that are dispute and therefore is admissible.

CONTENTION 48: Environmental Justice - Corporate Welfare

Petitioner's reassert that the issue of fair trade is a material issue of fact and law that is relevant to the proposed 20 year license. Entergy and the nuclear industry are spending billions of dollars, including millions of taxpayer dollars, to promote false propaganda about how inexpensive, renewable and clean. The Commission may use it's discretion to consider the true carbon foot print of nuclear power from mining to decommissioning, which is comparable to coal fire plants and to require a comparative study of the true costs, specifically the tax dollars used to support nuclear vs. any other energy technology in order to even the playing field.

Large communities of sustenance fisherman are ingesting and feeding life threatening tritium and strontium laced fish and shellfish to their families caused by the ongoing leaks at Indian Point. These leaks will continue during the proposed 20 year license period, rather than decommissioning and cleaning up the site to prevent such contamination.

In accordance with 10 C.F.R. 2.309(f)(3) and *Consolidated Edison Co. (Indian Point, Units 2 & 3)*, CLI-01-19, 54 NRC 109, 132 (2001), where both Petitioners independently established standing, the Presiding Office has the discretion to permit Petitioners to adopt the others' contention early in the proceeding. Petitioners join and adopt Clearwater's contention number on this issue.

Once Petitioner is accepted as a party we will apply for a waiver to consider this issue as a Category 2, site specific issue.

In accordance with 10 C.F.R. 2.309(f)(3) and *Consol. Edison Co. (Indian Point, Units 2 & 3),* CLI-01-19, 54 NRC 109, 132 (2001) where both Petitioners have independently established standing, the Presiding Officer may permit Petitioners to adopt the others' contention early in the proceeding. Petitioners join and adopt Clearwater's, and any other parties, contention(s) on this issue.

Contention 49: Global warming- Withdrawn

CONTENTION 50: Replacement Options: Stakeholders contend that the energy produced by Indian Point can be replaced without disruptions as the plants reach the expiration dates of their original licenses.

Applicant have failed to consider reasonable alternatives for 2158 MW of electricity, as required by 10 CFR 51. They on consider solar and wind as options to carry base load, and totally ignore the stability of geothermal and wave generated power. Additionally they incorrectly repeat in their answer that answer solar and wind are not always available and is speculative. Energy's refusal to acknowledge the ability of alternative energy to replace Indian Point is both short sighted and self-serving. They ignore current state of art technologies, including nanosolar and small wind generation which produces energy on cloudy and rainy days, and on days with little or no wind.

The failure of the Applicant and Staff to consider reasonable replacement energy is evidenced a narrow and closed minded approach that denies the current feasibility sustainable energy.

The Levitan Associates report and the Academy of Science report sponsored by Congresswoman Nita Lowey serve as expert reports that support Petitioners reasonable approach to replacement energy as a reasonable alternative to Indian Point continued operation during the proposed 20 year license period.

Simply if the incentives and tax subsidies granted to the nuclear industry and Entergy specifically was used to build sustainable energy systems the energy produced by Indian Point could be completely replaced. This is not speculative but factual.

Entergy's failure to provide a comprehensive study of replacement energy is inadequate and self serving. Entergy's conclusionary statement that "alternative simply cannot with current technology, provide the necessary amount of baseload power" is misleading and unsupported by expert witness rebuttal. Communities in the United State such as Sacramento have closed nuclear plants and have produced more than sufficient replacement energy, as well as created new jobs and economies. Energy's failure to present reasonable alternative fails to fulfill the requirements of 10 CFR 51 and is complete inadequate.

Thus, contention 50 meets the criteria for admissibility and must be admitted.

CONTENTION 50-1: Failure to Address Environmental Impacts of Intentional Attacks & Airborne Threats

Entergy's failure to address the environmental impacts and costs of intentional attacks and airborne threats of terrorism is unjustified especially at Indian Point the uniquely most attractive and vulnerable terrorist targets in the nation. The fact that the 9/11 terrorist flew directly over Indian Point and considered it as a target prior to settling on the World Trade Center causes this issue to be germane to the relicensing proceedings.

For the Commission not to require the Applicant to comply with the Ninth's Circuit's remand in the Diablo Canyon proceeding, is unreasonable in relicensing proceedings for Indian Point. The Commission refusal not to require the consideration of the impacts of a terrorist attack is a failure of the Commission to up hold their organizing mandate to adequately protect the public health and safety in violation of the Administration Procedure Act. Therefore, this Contention raises material issues of fact and law that are admissible and should be heard.

Contention 51: Inability to Access Proprietary Documents Impedes Adequate Review of Entergy Application for License Renewal of IP2 LLC and IP3 LLC.

Entergy claims that Petitioners assertion that proprietary information was withheld is incorrect. Petitioner's reiterate with specificity that the documents Entergy failed to provide are: the CLB including all modifications, exemptions, exceptions and deviations, and additions to such commitments over the life of the license, and appendices thereto; orders, license conditions, exemptions, exceptions and deviations; and technical specification and extensive redactions in the FSAR, UFSAR, including leak reports and leak maps that were shown at public meetings, but specifically denied to Susan Shapiro and other Petitioners, upon multiple requests to Entergy and the NRC dated 6/29/07, 7/6/07 and 9/4/07 (attached hereto). Entergy claims that Petitioners never contacted Entergy, when in fact Susan Shapiro had attempted through numerous communications attached hereto to obtain such information. NRC representative Richard Barkley of the NRC has told FUSE that the maps are proprietary property of Entergy. They will not become available until after the NRC receives Entergy's leak report later this fall, which makes the October 1, 2007 deadline to file Intervener Petitions highly prejudicial in favor of the licensee at the expense of the Stakeholders and other citizens whose best interests are supposed to be served by this Federal regulatory body.

Clearly, these leak maps and the upcoming leak report contain vital information directly related to potential environmental impacts and infrastructure aging issues, and consequently Entergy's LRA. The maps are necessary for Stakeholders to file properly and fully documented Intervener contentions.

In fact, the NRC used these maps to discuss the leaks in public meetings with representatives of Riverkeeper, Clearwater and IPSEC. In addition these maps, minus the Cesium map, were displayed in the lobby of a public meeting, however copies were unavailable.

Documents that have been made unavailable under the claim of proprietary information denying Petitioners their constitutional rights to redress, as required in the guidelines of the NRC Code of Regulations meant to protect human health and safety.

Therefore, this contention must be admitted.

SARAH L. WAGNER

Reference 1

Reference 1

Reference 1

MILTON B. SHAPIRO, ESQ.
SUSAN H. SHAPIRO, ESQ.
ATTORNEYS AT LAW

SHS@OURROCKLANDOFFICE.COM

21 PERLMAN DRIVE
SPRING VALLEY, NY 10977
(845) 371-2100 TEL
(845) 371-3721 FAX

12/3/07

Honorable Chairman Klein
Nuclear Regulatory Commission
Washington, DC 20555
chairman@nrc.gov

Office of Inspector General
Att: George Mulley
Office of the Inspector General
Mail Stop 05-E13
11555 Rockville Pike
Rockville, MD 20852
gam@nrc.gov

CONFIDENTIAL
Security Related Information
Withhold under 10 CFR 2.390

RE: Objection to the NRC's grant of a finding of no significant hazard with regard to an exemption to the requirements under Federal Rules to be reflected in a forthcoming Safety Evaluation and resulting in an amendment to License No DPR 64 for Indian Point Unit 3, Notice published on October 4, 2007, in the Federal Register. and Petition to Reopen Consideration of the Exemption, and Petition for Leave to Intervene and Request a Hearing on the above issue

Dear Honorable Chairman Klein and Office of the Inspector General:

Please accept for filing the enclosed Objection to the NRC's grant of an exemption to the requirements under Federal Rules to be reflected in a forthcoming Safety Evaluation and resulting in an amendment to License No DPR 64 for Indian Point Unit 3, Notice published on October 4, 2007, in the Federal Register, Petition to Reopen Consideration fo the Exemption, and Petition for Leave to Intervene and Request a Hearing.

Because this is a matter of national security, this document is confidential. It identifies that fire protection is an issue of security infrastructure, and it includes an analysis that expressly addresses issues of concern for national security, therefore we request that only a redacted copy will be published and docketed on ADAMS.

We are filing this Petition as CONFIDENTIAL.

Your prompt attention to this matter is greatly appreciated.

Sincerely yours,

Susan Shapiro
Representing:
New York State Assemblyman Richard Brodsky
Westchester Citizen's Awareness Network
Rockland County Conservation Association
Public Health & Sustainable Energy
Beyond Nuclear
Sierra Club – Atlantic Chapter

UNITED STATES
NUCLEAR REGULATORY
COMMISSION

In the matter of

ENTERGY NUCLEAR INDIAN POINT 3, L.L.C,	) License No. DPR 26
And Entergy Nuclear Operations, Inc. and	) and
Entergy North East, Inc.,	) License No. DPR 64
regarding the Indian Point Energy Center	)
Unit 3 License Amendment	)Docket No. 50-247
Regarding Fire Protection Program	)Docket No. 50-286

NOTICE OF APPEARANCE

Susan H. Shapiro, on December 3, 2007 and pursuant to 10 CFR §2.314(b) gives notice of her appearance on behalf of Westchester Citizen's Awareness Network , Citizen's Awareness Network, Rockland County Conservation Association , Public Health and Sustainable Energy, Sierra Club – Atlantic Chapter, Beyond Nuclear and New York State Asscmblyman Richard Brodsky. The undersigned is a member of good standing of the bar of one ore more Courts of the United States, and have been duly retained by the above mentioned groups and individuals to represent them in this matter.

CERTIFICATE OF SERVICE

I, Susan Shapiro, do hereby certify that on this 3rd day of December, 2007, an electronic copy of Westchester Citizen's Awareness Network, Citizen's Awareness Network, Rockland County Conservations Association, Public Health and Sustainable Energy, and Sierra Club – Atlantic Chapter, Beyond Nuclear, and New York State Assemblyman Richard Brodsky, Objection to the NRC's grant of an exemption, Petition to Reopen Consideraton of the Exemption and Petition for Leave to Intervene and Request a Hearing, with regard to fire the protection exemption request of Entergy 3 LLC, and Entergy Nuclear Operations, Inc, were sent by email, and CD electronic copies by US mail postage prepaid, and if request a hard copy will be send to:

Office of the Secretary
Nuclear Regulatory Commission
1 Flint North
11555 Rockville Pike
Rockville, Maryland 20852
elj@nrc.gov

Entergy Nuclear Operations, Inc.
440 Hamilton Ave.
White Plains, NY 10601

Kathryn M., Suttorn, Esq
Paul M. Bessette, Esq.
Martin J. O'Neill, Esq.
MORGAN, LEWIS & BOCKIUS, LLP
1111 Pennslyvania Avenue N.W.
Washington, DC 20004
(email ksutton@morganlewis.com
email pbessettc@morganlewis.com
email martin.o.neill@morganlewis.com

Director, Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation
Catherine Haney cxh@nrc.gov
Mark Kowal mxk@nrc.gov

Hearing Docket
hearingdocket@nrc.gov

Senator Hillary Clinton
Geri_Shapiro@clinton.senate.gov

Congressman Eliot Engel
Brian.Skretny@mail.house.gov

Congressman John Hall
susan.spear@mail.house.gov
Ryan.McConaghy@mail.house.gov

Congresswoman Nita Lowey
justin.wein@mail.house.gov

Assemblyman Richard Brodsky
richardbrodsky@msn.com

UNITED STATES
NUCLEAR REGULATORY COMMISSION

In the matter of

ENTERGY NUCLEAR INDIAN POINT 2, L.L.C, ENTERGY	)	
NUCLEAR INDIAN POINT 3, L.L.C, And Entergy Nuclear	)	License No. DPR 26 an
Operations, Inc. and Entergy North East, Inc., regarding the	)	License No. DPR 6
Indian Point Energy Center	)	
Unit 2 and Unit 3	)	Docket No. 50-247 an
License Amendment Regarding Fire Protection Program	)	Docket No. 50-28

OBJECTION TO GRANT OF EXEMPTION AND LICENSE AMENDMENT, PETITION TO REOPOEN FOR CONSIDERATION, PETITION FOR LEAVE TO INTERVENE and REQUEST FOR HEARING, AND CONTENTIONS

Westchester Citizen's Awareness Network (referred to hereinafter as "WestCAN"), Rockland County Conservation Association (referred to hereinafter as "RCCA"), and Public Health and Sustainable Energy (referred to hereinafter as "PHASE"), Sierra Club –Atlantic Chapter ("Sierra Club"), Beyond Nuclear, and New York State Assemblyman Richard Brodsky ("Brodsky") , are individually and jointly referred to hereinafter as "Stakeholders", pursuant to 10 CFR § 2.309 (d) and (e), object to the Nuclear

Regulatory Commission's grant of an exemption to the requirements under federal rules in an amendment to License No DPR 64 for Indian Point Unit 3. Exhibit No. FP1, by Entergy Nuclear Indian Point 3, LLC and Entergy Nuclear Operations, (collectively referred to as the Applicant, or Licensee, or Entergy) .

Stakeholders object to the NRC's grant of a finding of no significant hazard with regard to an exemption to the requirements under Federal Rules to be reflected in a forthcoming Safety Evaluation; and for failure to incorporate the requirements of 10CFR73.1 for IP3 as was mandated by Congress for Licensee DPR-64 for Indian Point Center Unit 3 (IP3), therefore Stakeholders request that consideration of the exemption request be reopened due to new, substantial and significant information, and Stakeholders request a hearing under 10 C.F.R. §2.309 (a).

I. PARTICIPATION AS A MATTER OF RIGHT

A. WestCAN, RCCA, PHASE, SIERRA CLUB, BEYOND NUCLEAR and New York State Assemblyman Richard Brodsky have standing on their own behalf and on behalf of their members.

1. WestCAN is a grassroots coalition that has advocated for a nuclear free northeast and has consistently followed the events at Indian in order to keep the

public informed through its listserve, WestCAN has approximately five hundred members who live within the State of New York, in Westchester, Rockland, Putnam and Orange County, and who make their residences, places of occupation and recreation within fifty (50) miles of Indian Point, and whose concrete and particularized interests will be directly affected by this proceeding. WestCAN has participated in hearings on this issue 2005, Exhibit FP no. 20. WestCAN 's central office is located at 2A Adrian Court, Cortland Manor, NY which is within five miles of Indian Point and situated within the Plume Exposure Pathway (EPZ), also referred to as the Peak Fatality Zone.

2. RCCA has standing on its own behalf and on behalf of its members. RCCA is non-profit organization, founded in 1930 and incorporated in 1936. RCCA is dedicated to the conservation of our natural resources, promote sound land use, advocate clean air and water quality, develop proper drainage, support energy conservation and preservation of natural beauty. RCCA has membership of approximately 450, who live within the State of New York, primarily in Rockland, County, and who make their residences, places of occupation and recreation within twenty (20;) miles of Indian Point, and whose concrete and particularized interests will be directly affected by this

proceeding. RCCA 's central office is located in Pomona, NY which is within nine miles of Indian Point and situated within the Plume Exposure Pathway (EPZ), also referred to as the Peak Fatality Zone.

3. PHASE as standing on its own behalf and on behalf of its members. PHASE is a grassroots think tank, that advocates for the development and use of sustainable energy, in an effort to protect public health and safety, and the protection of the environment. PHASE has members who live within the State of New York, primarily in Rockland and Westchester Counties, and who make their residences, places of occupation and recreation within thirty (30) miles of Indian Point, and whose concrete and particularized interests will be directly affected by this proceeding. PHASE's central office is located at 21 Perlman Drive, Spring Valley, NY 10977, which is within eleven miles of Indian Point and situated within the Plume Exposure Pathway (EPZ), also referred to as the Peak Fatality Zone.

4. SIERRA CLUB, ATLANTIC CHAPTER has standing on its own behalf and on behalf of its members. The Sierra Club is North America's oldest, largest and most influential grassroots environmental organization. is a

non-profit, member-supported, public interest organization that promotes conservation of the natural environment through public education and lobbying. Grassroots advocacy has made The Sierra Club America's most influential environmental organization. Founded in 1892, the Club is now more than 700,000 members strong. The Atlantic Chapter applies the principles of the national Sierra Club to the environmental issues facing New York State

SIERRA CLUB, Atlantic Chapter has 45, 000 members who live within the State of New York, including in the Hudson Valley, including New York City, and who make their residences, places of occupation and recreation within fifty (50) miles of Indian Point, and whose concrete and particularized interests will be directly affected by this proceeding, many of who live within the Peak Injury Zone.

5. BEYOND NUCLEAR, located at Nuclear Policy Research Institute 6930 Carroll Avenue, Suite 400 Takoma Park, MD 20912 has standing on its

own behalf and on behalf of its members. Beyond Nuclear aims to educate and activate the public about the connections between nuclear power and nuclear weapons and the need to abandon both to safeguard our future. Beyond Nuclear advocates for an energy future that is sustainable, benign and democratic.

6.New York State Assemblyman Richard Brodsky of the 92nd district, has standing on his own behalf and on behalf of his constituents who live in Westchester County, Town of Greenburg, Ardsley, Dobbs Ferry, Elmsford, Hartsdale, Hastings, Irvington, Scarsdale, Tarrytown and part of White Plains, and Town of Mount Pleasant, including Hawthorne, Briar Cliff, Pleasantville, Sleepy Hollow, Thornwood. Valahalla, North Yonkers. His office is located at 5 West Main Street, Elmsford, NY 10523.

WestCAN, RCCA. PHASE, SIERRA CLUB, BEYOND NUCLEAR and New York State Assemblyman Richard Brodsky meet the requirements of 10 CFR §2.310(d) for a full adjudicatory hearing on all contentions it raises, WestCAN, RCCA. PHASE, SIERRA CLUB, BEYOND NUCLEAR and New York State Assemblyman Richard Brodsky do not concede the procedures of 10 CFR §2.310 which restrict use of full adjudicatory hearing procedures are lawful and reserves the right to challenge, in an appropriate legal forum, these procedures, as applied to WestCAN, RCCA. PHASE, SIERRA CLUB, BEYOND NUCLEAR and New York State Assemblyman Richard Brodsky in this case, should that be necessary to permit WestCAN, RCCA. PHASE, SIERRA CLUB, BEYOND NUCLEAR and New York State Assemblyman Richard Brodsky to fully adjudicate the important nuclear safety and environmental issues it raises.

C. WestCAN, RCCA. PHASE, SIERRA CLUB, BEYOND NUCLEAR and New York State Assemblyman Richard Brodsky Meet Prudential Standing Requirements

In addition, Courts have created a prudential standing requirement that if a petitioner's interests fall within the "zone of interests" protected by the statute on which the claim is based. *Bennett v. Spear,* 520 U.S. 154, 162(1997). The Atomic Energy Act and NEPA, the statutes at issue here, protect the same interests of protecting public health and safety, that are held by WestCAN, RCCA. PHASE, SIERRA CLUB, BEYOND NUCLEAR and New York State Assemblyman Richard Brodsky's constituents, and furthered by WestCAN, RCCA. PHASE, SIERRA CLUB, BEYOND NUCLEAR and New York State Assemblyman Richard Brodsky's purpose.

II. WestCAN, RCCA. PHASE, SIERRA CLUB, BEYOND

NUCLEAR and New York State Assemblyman Richard Brodsky DO NOT WAIVE THEIR RIGHTS TO SUBMIT SUPPLEMENTAL CONTENTIONS AND AMEND THE CONTENTIONS SET FORTH HEREIN, AND TO OTHER PROCEDURAL MATTERS

A. Right to supplement and amend contentions is not waived.

WestCAN, RCCA. PHASE, SIERRA CLUB, BEYOND NUCLEAR and New York State Assemblyman Richard Brodsky are submitting a statement of the contentions that reflect the concerns of the Stakeholder community and should be accepted for hearing by the Nuclear Regulatory Commission on behalf of WestCAN, RCCA. PHASE, SIERRA CLUB, BEYOND NUCLEAR and New York State Assemblyman Richard Brodsky members and broad constituency. The contentions submitted herein should not be deeded to waive WestCAN, RCCA. PHASE, SIERRA CLUB, BEYOND NUCLEAR and New York State Assemblyman Richard Brodsky's right to submit further contentions in the future or amend the contentions set forth herein. Further, WestCAN, RCCA. PHASE, SIERRA CLUB, BEYOND NUCLEAR and New York State Assemblyman Richard Brodsky reserves their right to submit additional contentions, and amend the contentions set forth herein.

B. Efficiency of Cross Examination of Expert or Fact Witnesses

The most efficient manner by which statutory rights can be exercised is to allow both depositions and live testimony to the extent the issues are not fully developed during discovery. Although not specifically mentioned in 10 CFR §2.102, cross-examination of witnesses will be more efficient when possible for WestCAN, RCCA. PHASE, SIERRA CLUB, BEYOND NUCLEAR and New York State Assemblyman Richard Brodsky and the Applicant to submit cross-examination outlines five days before the hearing, to alert each witness to the subjects which the parties will explore.

WestCAN, RCCA. PHASE, SIERRA CLUB, BEYOND NUCLEAR and New York State Assemblyman Richard Brodsky have the right to seek production of documents, if for no other reason than production of documents will facilitate interrogation of witnesses and narrow the scope of their examination. Otherwise, witnesses will be asked questions about issues which are addressed in documents which either are not present during the interrogation or the analysis of which will require a hiatus in the interrogation.

Relevant documents and cross-examination outlines are hereby requested to be submitted by all parties wherever possible, at least five days in advance such that the witness may be prepared to fully answer the questions posed.

C. WestCAN, RCCA. PHASE, SIERRA CLUB, BEYOND

NUCLEAR and New York State Assemblyman Richard Brodsky (the Stakeholders) contend that the Nuclear Regulatory Commission and Applicant have had and will continue to have ex parte communications in violation of the requirements of Title 5, Part 1 Chapter 5 subchapter 11 § 557. Ex parte communication by the parties shall adhere in the strictest sense to the requirements of Title 5, Part I Chapter 5 subchapter II, §557.

The Stakeholders request that the NRC follows the regulations with regard to ex parte communications with the Applicant as required by Title 5, Part 1, Chapter 5 subchapter II§557. The sections that have particular relevance are provided below. In any agency proceeding which is subject to subsection (a) of this section, except to the extent required for the disposition of ex parte matters as authorized by law:

(i) No interested person outside the agency shall make or knowingly cause to be made to any member of the body comprising the agency, administrative law judge, or other employee who is or may reasonably be expected to be involved in the decisional process of the proceeding, an ex parte communication relevant to the merits of the proceeding;

(ii) No member of the body comprising the agency, administrative law judge, or other employee who is or may reasonably be expected to be involved in the decisional process of the proceeding, shall make or knowingly cause to be made to any interested person outside the agency an ex parte communication relevant to the merits of the proceeding;

(iii) A member of the body comprising the agency, administrative law judge, or other employee who is or may reasonably be expected to be involved in the decisional process of such proceeding who receives, or who makes or knowingly causes to be made, a communication prohibited by this subsection shall place on the public record of the proceeding:

(A) All such written communications;

(B) Memorandum stating the substance of all such oral communications; and

(C) All written responses, and memoranda stating the substance of all oral responses, to the materials described in clauses (i) and (ii) of this subparagraph

(iv) Upon receipt of a communication knowingly made or knowingly caused to be made by a party in violation of this subsection, the agency, administrative law judge, or other employee presiding at the hearing may, to the extent consistent with the interests of justice and the policy of the underlying statutes, require the party to show cause why his/her claim or interest in the proceeding should not be dismissed, denied, disregarded, or otherwise adversely affected on account of such violation; and

(v) The prohibitions of this subsection shall apply beginning at such time as the agency may designate, but in no case shall they begin to apply later than the time at which a proceeding is noticed for hearing unless the person responsible for the communication has knowledge that it will be noticed, in which case the prohibitions shall apply beginning at the time of his acquisition of such knowledge.

(vi) Therefore the Nuclear Regulatory Commission bound under these regulations throughout the License Renewal Application proceedings may not have ex parte communications with the Applicant.

III. STAKEHOLDERS SUBMIT SIX ADMISSIBLE CONTENTIONS

The following summary clearly raises in scope, material issues, supported by facts and expert opinions, that raise genuine issues of material law or facts, regarding the NRC grant of Entergy's modified exemption request to reduce fire safety standards for Indian Point 3, from 1 hour to 24 minutes, approved by on September 28, 2007, and published in the Federal Registry on October 4, 2007.

SUMMARY OF ISSUES AND CONTENTIONS

The current license amendment, Indian Point 3 less protected from fire than Browns Ferry plant was in 1975. Specifically, in less than 24 minutes a fire at Indian Point 3 could cause irreversible loss of control to the reactor, and loss of use of the emergency cooling systems power cables. The new exemption from federal law flagrantly disregards the Presidential order for protecting nuclear power against Design Basis Threat, partially codified in 10CFR73.1.

The 1975 fire at the Browns Ferry Nuclear Plant damaged more than 1600 electrical cables and required almost eight hours to contain. It caused loss of ability to control reactor power and to safely shut down the plant during that period. Prior to Brown's Ferry the fire potential of insulation on cables was not considered to be relevant by the industry or the NRC in establishing standards by which nuclear plants should be constructed.

Since then the NRC have reacted with dysfunctional and failed attempts to perform Congress' mandate: " To protect the health and safety of the public". After more than 30 years since the Browns Ferry fire the NRC continues to allow prima facie violations of federal rules by the nuclear industry that directly reduce adequate protection of public health and safety.

By the NRC granting Entergy the exemption on October 4, 2007, they have granted a substantial reduction in Fire Protection Program for Indian Point 3, and condoned the dangerous conditions currently at the facility. This exemption to federal rules, has made Indian Point 3 more vulnerable to fire then Browns Ferry was in 1975. The reduction from a 1 hour fire rating to a 24 minute fire rating, is a significant change in the Current License Basis and Design Basis.

Now, a single fire ignited in an electrical cable tunnel must be fully detected, responded to by a fire brigade, and FULLY EXTINGUISHED in less than 24 minutes, or loss of the control of reactor power will occur, and combined with expected valve openings, will likely cause catastrophic core melt.

Since 1995 the NRC has permitted ongoing violations, and noncompliance by plant operators. This exemption codifies these violations, and permits substantial reduction in defense-in-depth.

The exemption granted did not add in the potential of a deliberate act of sabotage or terrorism, as is required under federal rules mandated after September 11, 2001. The NRC and Entergy failed to consider the act of an insider with specific knowledge of the target, as is required under the Design Basis Threat (DBT), codified in 10CFR73.1.

Under this exemption one individual could set fires in both Unit 2 and Unit 3, causing a melt down both plant, in a matter of hours. This does not require smuggling in the combustibles needed for ignition for sufficient burn time, nor, the act of more than one individual.

The exemption granted on October 4, 2007, only 6 year after 9/11 does not consider ignition of a fire by a light aircraft accidentally or deliberately crashing into the specific and easily identified, above-ground, tunnels, penetrating a two foot wall of concrete, and thus igniting fires. Due to the reduction in fire protection from 1 hour to 24 minutes cables required for safe shut down will be destroyed within 24 minutes

Fire is the single highest threat to plant operational safety.

BACKGROUND

In 1979, four years after Browns Ferry, the NRC enacted new federal regulation intended to strengthen fire protection, however, in spite of new regulation strengthening fire protection standards, the NRC began granting exemption request and after exemption request, for licensee holders.

Over 900 exemptions to date have been granted by the NRC on fire safety. In particular, the one hour rule for suppression without manual action has been set aside by numerous licensees. Licensees routinely credited manual operator action inside the one hour limit to safely shutdown the plant. Many licensees did not even bother to request exemptions, but simply credited manual actions in the safe shut down procedures thus deliberately setting aside the federal rules.

When the industry lobbied the NRC they adopted a cost benefit analysis disguised as a probabilistic analysis being codified in 10CFR50.48(c), "alternative analysis." Profits of the nuclear industry are now being weighed against protection of public health and safety. Unfortunately it appears that the bias is leaning heavily in favor of corporate profits.

<u>HEMYC fire wrap improperly tested and found to perform for only 24 minutes, instead of 1 hour, as advertised.</u>

In 1995 inspection reports the NRC specifically identified a wire wrap, fire protection, material known as **HemyC as not being properly tested, but accepted by the NRC for protecting electrical tunnels at Indian Point 3.** Full-scale fire tests recently performed by the NRC revealed that HemyC, a fire barrier system used to protect cables in electrical raceways in nuclear power plants, does not perform as designed. The outer covering of the barrier can shrink during a fire, opening joints in the material and potentially allowing the fire to damage cables inside. These results show that HemyC does not serve as a fire barrier for the full hour required.

Despite these new test that identified that HemyC could not withstand a fire for more than 24 minutes in certain cable set-us, required to be 1 hour it is still be used at Indian Point 3. The NRC issued Generic Letter 2006-03 in April 2006 to ensure that the affected licensees take appropriate corrective actions.

On August 16, 2007, Entergy notified the NRC that deficient design of the HemyC fire wrap would not withstand the originally proposed exemption of 30 minutes, but for an unknown duration with a best guess of 24 minutes --- and that guessed duration would only be *after plant modifications* were completed. The necessary modifications may remain unimplemented up to December 2008.

There was no public comment period . The changes made to the proposed exemption on August 16, 2007 where never made formally public, *almost no one noticed* until after the grant. Even the New York State Attorney General's Office who objected on the same day, believed that the exemption was still pending.

Complete and proper analysis of the implications on fire safety caused by the greatly reduced fire standard usually takes months. However, in a matter of a few short weeks the amended exemption request was accepted by the NRC.

The affect of NRC's grant of the October 4, 2007 exemption, are 1) reduction of fire safety parameters by more than 50%; 2) non-compliance by the operator for more than 10 year, is condoned, despite long term safety violations; 3) failure to consider public comment; and most importantly, 4) erosion of the time available to detect, respond and extinguish a fire that affects both *power* of emergency core cooling systems and the *controls* for those emergency systems and for normal control of reactor criticality itself.

The NRC's public statements regarding fire protection, plant security, and design basis threats are in direct contradiction of the approval of the amended exemption request, in violation of the requirements of 10CFR50.48

and Appendix R.

Congressional Hearings.

The Congressional Energy and Commerce Oversight Committee held a number of hearings questioning the Nuclear Regulatory Commission on the subject of Fire Protection beginning about fifteen years ago. Each NRC Chairmen listened, accepted responsibility, made commitments, and then failed to act.

Promises by the NRC Chairman Selin in 1993, and by NRC Chairman Meserve in 2001 to the Congressional Energy and Commerce Committee Oversight Committee on Energy and Safety were made independently, 8 years apart and each remain unfulfilled today.

Instead, of fulfilling commitments to improve fire protection compliance to the 1979 rule, the NRC has stripped down the technical basis and fundamental goals of the federal rules regarding fire protection with several initiatives enacting "alternative analysis" to those rules.

There is a substantial record of the NRC's mistakes 1980s and early 1990s, and in more recent hearings in 2004, 2005, and 2006 are obvious. The Nuclear Regulatory Commission was warned in 1993, and then admonished in 2001 for its failure to implement the 1979 rule, and recently questioned again regarding lack of fully implemented rules regarding Design Basis Threat, and the pending rulemaking regarding that by passes the key elements of the 1979 rule completely.

The NRC's failure to enforce the 1979 rules dates back more than 25 years. Portions of the DBT rule, have been side stepped since 2001. Then the NRC began an alternative approach to compliance based upon an industry lobbyist standard NFPA 805. The premise of the new approach lobbied by NEI and the NFPA is currently being codified by direct reference of NFPA 805 into federal regulations. It is based solely on probabilistic analysis, improperly grounded in unsubstantiated assumptions regarding fire event probabilities.

The Energy Policy Act of 2005 (EPAct), in response to September 11, 2001, compelled the NRC to improve fire protection coping ability across the nations fleet, yet instead of improving fire protection, the NRC is systematically reducing fire safety measures.

HISTORY OF FIRE SAFETY ISSUES

1993 – Congress Together With The NRC Office Of Inspector General Responded To Symptoms indicating a Troubled Agency:

In 1993 Congress called for hearings on Fire Protection, to correct problems with a fire-retarding material at nuclear power plants. The Justice

Department began a criminal investigation into whether the NRC and the nuclear industry 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 in 1993. See Exhibit FP No. 1

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. The current situation with HemyC, unfortunately is reminiscent of Thermo-Lag.

Investigations found Thermo-Lag was approved as a protective barrier in the early 1980s. The NRC staff, however, never conducted independent tests to determine if the material met federal standards.

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 Office of the 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 material in question, Thermo-Lag, was used in 79 nuclear power plants nationwide. See exhibit FP No. 2

During a 10 year period 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.

David Williams, Inspector General for the U.S. Nuclear Regulatory Commission, also told lawmakers the NRC " 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 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." He charged that the use of 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.

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." See Exhibit FP No 3.

Implementing Risk-Informed, Performance-Based Fire Protection

The Commission approved the 50.48(c) rule in May 2004, and published the rule in June. It took effect in July.

The Commission also unlawfully allowed the staff to use its discretion in enforcing certain fire protection issues for plants transitioning to the new rule. The enforcement discretion provided an incentive for licensees to adopt NFPA 805, even though it is completely unlawful.

It provided a "get out of jail card" for non-compliant licensees that failed to implement the rules enacted in 1979 with no penalty for violating federal rules and risking the health and safety of the public for decades. Subsequently, by the end of February 2006, operators of 42 reactors had sent letters of intent indicating their commitment to adopt the voluntary standard.

Manual Fire Safety Protection

Licensees are required to protect plant equipment necessary for safe shutdown using a combination of physical separation, barriers, and methods to detect and control or extinguish fires. The NRC has also reviewed and approved operator manual actions, as another acceptable method, to safely shut down the plant in the event of a fire. An example is manually opening a valve to prevent it from closing improperly during a fire.

There are a substantial number of licensees relying on operator manual actions that have not been reviewed and approved by the NRC to mitigate fires in fire areas with redundant safety trains (commonly referred to as III.G.2 areas since Section III.G.2 of Appendix R to 10 CFR 50 provides the requirements).

The NRC staff proposed a rule change that would enable the licensee to demonstrate acceptability of manual actions used to safely shut down a plant in the event of a fire. **The rule's primary objective was to improve efficiency by minimizing the number of exemption requests.** This is an unacceptable rationale for avoiding the basis of federal rules enacted in 1979, in response to the Browns Ferry fire.

Stakeholders contend that the current failure of fire protection at Indian Point and the NRC rushed approval of the amended exemption request that reduces the 1 hour requirement to only 24 minutes is a violation of the Presidential Order to protect nuclear power plants against Design Basis Threats- partially codified in 10CFR73.1.

In defiance of Congress, the NRC has stripped down the rules by using so called "alternative analysis" favored by the nuclear industry and the nuclear industry lobbyists. "Alternative analysis" is a cost benefit analysis disguised as a probabilistic analysis being codified in 10CFR50.48(c). Profits of the nuclear industry are now being weighed against protection of public health and safety. Unfortunately it appears that the bias is leaning heavily in favor of corporate profits.

Stakeholders contend that the NRC has wrongfully granted the exemption from fire safety regulations for the following reasons of fact and law, that are within scope of the license amendment.

1. 24 minute exemption to a Appendix R, and 10CFR50.48 are incorporated into the plants operating license, and is as a matter of fact and law, an amendment to the operating license.

2. Fire or fires could be set by insiders, and could quickly bring down both Indian Point 2 and Indian Point 3, based on the 24 minutes rule, in violation to the Design Basis Threat10 CFR 73.1.

3. A fire caused by an aircraft penetrating a two foot thick above ground tunnel could not be extinguished in 24 minutes and could prevent safe shut down.

4. The original exemption request March 24, 2006, was for a reduction from 1 hour to 30 minutes. Then after the license renewal application has already been submitted by Entergy, Entergy amended the exemption request from 30 minutes to 24 minutes. See exhibits FP No, 5 and Exhibit FP No. 6

The public was not aware of this. Although the NRC could not have done an adequate independent Safety Evaluation in a few weeks, the NRC approved this in a only nine weeks later.

NRC staff have explained that the NRC approved the exemption on the bet that the industry would fully adopt NFPA 805, Performance based Standard for light water Reactor Electric Generating Plants, 2001 edition, now codified under 10CFR50.48(c).

5. The NRC is aware of multiple plants directly defying the present rules regarding fire protection with prima

facie evidence in operational procedures of depending on manual actions to save essential equipment, without exemptions even requested. The NRC approved the amended exemption request in violation of promises to Congress to correct deficiencies from a similar material failure – thermolag affecting 79 plants—instead tolerating of deficiencies.

6. The exemption was argued by Entergy as not requiring an environmental assessment—because the previous exemptions did not require the assessment. This again is a fatally flawed argument, the difference between fire protection of 1 hour instead of 24 minutes has significant Environmental consequences, that must be fully understood. The NRC approval of this exemption is a violation of NEPA.

7. The NRC has violated §51.101(b) in allowing changes to the operating license be done concurrently with the renewal proceedings. The exemption request was modified by Entergy on August 16, 2007 for IP3, only two weeks after of the License Renewal Application Renewal was accepted by the NRC on August 2, 2007.

Background and Summary of Contention

The fire protection program advanced by Entergy for IP 3 is deficient in that it fails to safeguard the control room operation of achieving safe shutdown of the reactor in the event of a significant fire. The program is based on preposterously optimistic time and capability assumptions that significantly increase the likelihood of uncontrolled reactor criticality, inadequate cooling of the reactor core and the potentially catastrophic outcome of a core melt.

Specifically, the highly implausible scenario upon which Entergy gambles is that: fire ignition, fire detection, confirmation thereof, a determination of proper control acts, fire brigade formation and dispatch, and conflagration extinguishment, can all occur in a time span of less than 24 minutes. Moreover, under conditions of high heat, choking and blinding smoke and with electrically energized circuits present, plant responders will also be able to save operability of major cables required for safe shutdown. And all of the necessary actions and outcomes may be relied upon, even should the fire be one of several unfolding plant emergency conditions.

Entergy's dubious fire protection plan is part and parcel of a series of requests for exemptions from critical and long-standing fire (and other) safety regulations. The basic fire safety regulatory scheme was instituted nearly 30 years ago after a major fire at the Browns Ferry nuclear plant in Alabama, burned out of control for almost seven hours and nearly disabled the reactor's emergency core cooling system.

To reduce the critical threat, exposed by Browns Ferry, of a fire disabling all redundant safe shutdown electrical circuits in the same zone of a nuclear power plant, regulations were enacted to require either significant physical separation between cable trays and conduits, or the use of physical fire barriers. Fire barriers can be in the form of fireproofing material or insulation wraps. However the barrier must be qualified to withstand standardized American Standard Test and Measures (ASTM) E-119 furnace conditions. [Section III.G. of 10 CFR 50 Appendix R.]

At IP3, one such fire barrier employed is an insulation system known under the brand name HemyC, which is required to be able to withstand fire conditions for at least 1 hour (as per the requirements of 10 CFR 50.48, Appendix A, Branch Technical Position 9.5.1, and Appendix R). The 1 hour period was designated as necessary to protect safe shutdown power, instrumentation and control circuits from fire damage in the event of a significant fire.

In 2005, however, independent laboratory tests revealed that Hemcy, could, in fact, fail in as little as 15 minutes. According to published test results, the HemyC material was identified to shrink under standardized fire test conditions, opening seams and exposing electrical circuits vital to the safe shutdown of the reactor to fire damage, potentially rendering them inoperable as well as introducing electrical short circuits to safety significant associated circuits.

In response to this safety problem, Entergy has asked the NRC for an exemption from the rule requiring the fire barrier to be able to hold up for at least 1 hour. In doing so, Entergy has effectively asked the NRC to alter the very assumptions of how a fire can affect areas containing critical plant cabling and equipment and how long fires might last.

Simply put, Entergy wants the NRC to degrade the fire safety rules to accommodate Indian Point's degraded fire safety condition.

A Viable Protection Program is Central to the Safety of a Nuclear Power Plant

The NRC "Severe Accidents study (NUREG-1150) recognized that fire is a significant risk contributor to core damage frequency, as much as 50 percent of the total risk and that fire can both initiate a nuclear accident and compromise the operator's ability to control reactor shutdown and maintain it in stable cool down. This study further recognized that a typical nuclear power station will have 3 to 4 significant fires.

As a preliminary matter, a fire protection program must take due cognizance of the realities of fire. (This should be obvious, but the posture of Entergy indicates that such realities are not apparent to all.)

The Applicant requested the NRC grant an exemption from federal rules for a extinguishing a fire in the tunnel whose duration was unknown. Applicant stated that class 1E cables in trains separated by less than 12 inches would be inoperable in less than 24 minutes. These cables are vital for operating both normal and emergency systems for the safe operation and emergency shutdown of the plant.

Loss of these power cables together with diminished operation of safety related valves, (such as, Pressurizer Operator Relief Valve, Core Spray System operation, or the Charging System), which may reasonably be anticipated during a tunnel fire, can render the reactor energy uncontrolled and the reactor condition degradation immitigable. Both control and Power cables run through the two tunnels. See exhibit FP No. 9, and 10. On December 17, 2003, President Bush issued Homeland Security Presidential

Directive 7 (HSPD-7), which supersedes portions of PDD-63 and clarifies that the Department of Energy is the lead agency with which the energy industry will coordinate responses to energy emergencies.

This condition has been known since 1995, See exhibit FP No. 8 when NRC inspectors reviewed the in-progress plans to install an untested fire wrap HemyC in the tunnels, and acknowledged lack of ASTM 119 testing. Despite these issues, the NRC inspectors approved the modification with the understanding that testing of the wrap would be done at a later date. Doing this allows Applicant to, in effect, make "an agreement to agree".

It defies logic that 11 years, later the NRC declared the HemyC material unacceptable to meet 1 hour fire limits when it published Generic Letter 2006-03.

The improper design of the tunnel and the susceptibility of the tunnel to single failure criteria was identified in 1976, in a report by the Project Manager, Division of Project management, U.S. Nuclear Regulatory Commission on February 6, 1976. As early as this report, the operator and the NRC both knew that both tunnels were required to be functional in order to safely shut the plant down. . See page 19 of Exhibit FP no. 10 where the NRC points out that system logic requires that two, of out three, systems be operable following an accident.

In addition, the problem of associated circuits was not dealt with at all. This entire issue languished for years. The 1995 NRC inspection report acknowledges use of HemyC material inside containment. Yet, the Applicant's LRA does not provide a resolution of unacceptable burn times for that configuration.

Title 10 of the Code of Federal Regulations (10 CFR), Part 50, [Section] 50.48, requires that nuclear power plants that were licensed before January 1, 1979, including IP2 and IP3, must satisfy the requirements of 10 CFR Part 50, Appendix R, Section III.G. Subsection III.G.2 addressing fire protection features for ensuring that one of the redundant trains necessary to achieve and maintain hot shutdown conditions remains free of fire damage in the event of a fire. Subsection III.G.2.c provides use of a 1-hour fire barrier, fire detection and automatic fire suppression in the area, as a method to comply with this fire protection requirement.

In an NRC letter and safety evaluation (SE) dated February 2, 1984, the NRC improperly granted the applicant exemptions from the requirements of Appendix R, Section III.G.2, for Fire Area ETN-4 (Fire Zones 7A, 60A and 73A). The exemption was applicable where redundant safe-shutdown trains are not separated by more than 20 feet, without intervening combustibles or fire hazards, and that redundant safe-shutdown trains are not separated by 1-hour rated fire barrier in an area protected by automatic fire detection, and suppression systems.

The exemption was based on the minimum of 12" spatial separation between the redundant trains, minimal fire hazards in the area, the use of asbestos-jacketed flame-retardant cables, and the installed automatic fire detection and cable tray suppression systems.

Following a comprehensive reassessment of the IP2 & IP3 Appendix R compliance basis, the need for additional separation measures was identified and the untested fire barrier system was installed to provide 1-hour rated fire barriers on several redundant safe-shutdown raceways in Fire Area ETN-4 (Fire Zones 7A, 60A and 73A) for Unit 3. By Safety Evaluation dated January 7, 1987, the NRC accepted the use of 1-hour rated fire barriers in the above fire area and confirmed continued validity of the exemption granted by the February 2, 1984 SE. IP3 used the untested HemyC fire barrier system to provide the 1-hour rated fire barriers. In the January 7, 1987 SE, the NRC also approved an exemption from Appendix R, Section III.G.2, separation requirements for Fire Area PAB-2 (Fire Zone 1) allowing redundant safe-shutdown trains to be separated by more than 20 feet without intervening combustibles or fire hazards, and with an automatic suppression system.

This exemption required physical separation between redundant safe shutdown trains; low fire loading in the area; and continuation of the existing fire protection features, including an automatic fire detection system, manual hose stations and portable extinguishers; a partial-height non-combustible barrier designed to protect redundant equipment against radiant heat from a fire; and a 1 hour rated HemyC cable wrap around the normal power feed to the redundant Component Cooling Water (CCW) Pump 33.

Testing by a laboratory retained by the NRC in 2005 identified HemyC electrical raceway fire barrier system (ERFBS) as a nonconforming barrier, potentially failing in a little as 13 minutes and thus, not capable of providing a 1-hour fire rating, and Information Notice (IN) 2005-07, "Results of HEMYC Electrical Raceway Fire Barrier System Full Scale Fire Testing," Exhibit FP no. 11 and Generic Letter (GL) 2006-03, "Potentially Nonconforming HemyC and MT Fire Barrier Configurations," were issued to licensees to inform them of the issue and to collect information regarding HemyC fire barrier installations.

In response to GL 2006-03, the Applicant informed the NRC that it declared the HemyC Electrical Raceway Fire Barrier System Full Scale Fire Testing RFBS, IP3 inoperable, and implemented temporary compensatory measures, including an hourly fire watch and verification that fire detection systems are operable in the affected fire areas until compliance is restored for the HEMYC Electrical Raceway Fire Barrier System Full Scale Fire

Testing.

In a letter dated July 24, 2006, Applicant stated it would modify the installed HemyC ERFBS to provide only a 24 minute rated fire barrier for cable tray configurations and a 30 minute rating for conduit and junction box configurations between redundant trains of safe shutdown equipment and cables, i.e., allowing for fire barrier failure in less than half the time as the previously approved 1-hour fire barrier. Applicant asserted that IP3 did not need to employ a 1 hour fire barrier because there were minimal fire hazards and fire protection features in the affected areas.

In summary, by letter dated July 24, 2006, and supplemental letters dated April 30, May 23, and August 16, 2007, Applicant requested revisions to the pending exemptions from fire safety regulations for the Upper and Lower Electrical Tunnels (Fire Area ETN-4, Fire Zones 7A and 60A, respectively) and the Upper Penetration Area (Fire Area ETN-4, Fire Zone 73A), to allow only 24 minute rated fire barriers be used to protect redundant safe shutdown trains in lieu of 1 hour rated fire barriers. For the 41" Elevation CCW Pump Area (Fire Area PAB-2, Fire Zone 1). Applicant requested the existing exemptions to be revised to allow for only a 30 minute rated fire barrier to protect redundant safe shutdown trains located in the same fire area.

Besides the obvious reduction in adequate protection to public health and safety, the blinding speed that this exemption was granted, is stunning. It is doubtful that the NRC staff was able to rigorously evaluate the significant change in only a few short weeks.

Furthermore, this reduction allows fire protection at nuclear power plant sited within 50 miles of over 20 million people, to be inferior to that required by New York State Building codes, which require a provide either 1 or 2 hour firewalls in commercial buildings, depending on use.

There are numerous sufficient alternatives that could be used to retrofit the plant, to restore fire protection to at least one hour. This exemption is clearly a reduction of safety rules made to accommodate the financial interest of the Applicant, and is clear violation of the NRC's mandate to protect public health and safety.

Discussion

Pursuant to 10 CFR 50.12, the NRC may grant exemptions from the requirements of 10 CFR Part 50 when:

(1) the exemptions are authorized by law, will not present an undue risk to public health or safety, and are consistent with the common defense and security; and (2) when special circumstances are present.

One of these special circumstances, described in 10 CFR 50.12(a)(2)(ii), is that the application of the regulation is not necessary to achieve the underlying purpose of the rule. The underlying purpose of Subsection III.G.2 of 10 CFR 50, Appendix R, is to ensure that one of the redundant trains necessary to achieve and maintain hot shutdown conditions remains free of fire damage, in the event of a fire. The provisions of III.G.2.c through the use of a 1-hour fire barrier with fire detectors and an automatic fire suppression system is one acceptable way to comply with this fire protection requirement.

However, Applicant's most recent amendment to the exemption, modified it to reduce the requirement to 24 minutes was dated August 16, 2007. This was a modification of their exemption request dated July 24, 2006 in which they requested a reduction of the 1hour minimum requirement to 30 minutes. In addition on August 16, 2007 the Applicant acknowledged that in order to meet the reduced time of 24 minutes, it would require a modifications.

This is a significant amendment of IP3's operating license, as allows for far less than the minimum of 1 hour, fails to provide adequate protection and lacks even the most basic foundational support. (Such an analysis, for example, would patently require a detailed description of modifications that would need to be made to the cable trays and junction boxes in the tunnel.)

Stakeholders strongly object to the exemption being granted. The scenario upon which Entergy gambles, to wit: fire ignition, detection, confirmation, determination of proper control acts, fire brigade formation and dispatch, and extinguishment – all in less than 24 minutes – under conditions of high heat, smoke and with electrically energized circuits present, is profoundly implausible. Significantly, Applicant proffers no evidence that this scenario has been adequately tested or can be relied upon. Indeed the broadly available literature on fire safety as well as plain common sense leads to the conclusion that placing confidence in Applicant's scenario is foolhardy.

The Applicant asserts that fire hazards and ignition sources in both Fire Areas ETN-4 and PAB-2 remain materially unchanged from those described in the Safety Evaluations dated February 2, 1984, and January 7, 1987. For Fire Area ETN-4, the ignition sources consist of limited transient combustibles (in all fire zones), and several instrument cabinets and a 3kVA 480V/120V instrument power transformer in Fire Zone 73A.

Significantly, the class 1E cables in trains, separated by less than 12 inches, could well be rendered inoperable in under 24 minutes. These cables are vital for operating both safe operation and the emergency shutdown of the plant. Degradation or destruction of these power cables together with loss of full operation of safety related valves (such as the Pressurizer Operator Relief Valve, the Core Spray System or the Charging System) would be reasonably likely to occur during a plant fire in this tunnel. Under such circumstances, the 30,000 BTU of reactor energy could be rendered uncontrolled and the reactor condition degradation would probably be un-mitigatable.

Stakeholders assert the following: (1) the fire hazards analysis and the fire safe shutdown analysis are living documents that are an element of the Current License Basis. These documents require examination and reanalysis as the Applicant implements modifications to the facility. (2) The 1984 analysis was not updated until well beyond 10 years. The most recent safe shutdown analysis appears to be revision 2, dated August 2000, which is more than seven years out-of-date. Thus these analyses are historical and void, given the reality that modifications were made to the facility during the intervening years. Without the baseline analysis being kept current, it is essentially impossible for engineering analyses, engineering design changes, operational function changes and even the most fundamental changes to the facility, to be performed in conformance with 10 CFR 50.48 and Appendix R.

The 24 minute minimum can only be obtained after modifications of the cable trays and boxes occurred, such modification many not even be made until 2008. Thereby leaving the current unsafe conditions of non-compliance with Appendix R.

For the 41" Elevation CCW Pump Area (PAB-2, Fire Zone 1), the current IP3 Fire Hazard Analysis indicated a fire severity of less than 10 minutes. Combustibles include the CCW pump bearing lubricating oil and transient materials.

The HemyC-wrapped Box-Type Configuration installed in Fire Area ETN-4 (Fire Zone 73A) is comparable to Configuration 2G in NRC Test 2, *except for the lack of the stainless steel over-banding*. These enclosures are protected by a direct-attached 2"-thick HemyC blanket wrap. Both NRC and industry-sponsored tests of fire protection cable function when tested in accordance with ASTM E-119. To more closely reflect Configuration 2G, the Applicant is committed to install over- banding on the Box-Type Configuration at IP3. Cable Tray Configuration The HemyC-wrapped Cable Tray Configuration installed in Fire Area ETN-4 (Fire Zones 7A and 73A) is comparable to Configuration 2B and 2D of NRC Test 2. These cable trays are protected by a 1-1/2"-thick HemyC blanket wrap with a nominal 2" air gap between the protected cable tray and the blanket.

Fire tests conducted by both NRC and industry indicated that these HemyC-wrapped cable tray configurations will provide up to 24 minutes of thermal protection in accordance with the ASTM E-119 time-temperature profile.

The Applicant stated that administrative controls of hot work and transient combustibles allowed designated Fire Areas ETN-4 and PAB-2 as "Level 2" combustible control areas, which constrain transient combustibles to "moderate" quantities as follows, in both IP2 and IP3:

- 100 pounds of fire retardant treated lumber, or
- 25 pounds of loose ordinary combustibles or plastics, or
- 5 gallons of combustible liquids stored in approved containers, or
- One pint of flammable liquids stored in approved containers, or
- One 20 ounce flammable aerosol can.

With the proposed additional protection of electrical raceway supports and installation of over-banding on HemyC box configurations, the modified fire barrier configurations are expected to afford at least 24 minutes for cable tray configurations and 30 minutes of protection for conduit and box configurations; 50% or less than the time required by Design Basis.

Since the HemyC electrical raceway fire barrier system is expected to provide protection for redundant components and cables in the event of a fire, the NRC staff, inappropriately, concluded that the minimal combustibles in the areas and existing active/passive fire protection features can compensate for the reduction in Defense-in- Depth of objectives 3 and would not impact IP3 post-fire safe-shutdown capability.

Stakeholders disagree with this conclusion. Material facts in genuine dispute include the following:

(1) The proffered findings are not demonstrably applicable to IP3. Namely, the use of HemyC wrap to protect cabling critical for control and safe shutdown of the plant is based solely upon generic testing. No test configuration matches the conditions of the HemyC wrapped cable in the IP3 tunnel. Applicant is thus engaging in unsubstantiated speculation regarding longevity of the cable function.

(2) The unique characteristics of the EDG output voltage of 480 volts (as compared to 4160 volts) impose a much higher amperage through the cables, necessitating larger gauge cable and more energy lost in power transmission in the form of heat. The tested configurations do not account for these conditions, which are unique to Indian Point's emergency generators, and buses.

(3) The scenario upon which Entergy gambles, to wit: fire ignition, fire detection, confirmation, determination of proper control acts, fire brigade formation and dispatch, and extinguishment – all in less than 24 minutes – under conditions of high heat, smoke and with electrically energized circuits present, is highly unlikely, and cannot be relied upon as credible. Notably, in addition to putting out the blaze, plant responders would also need to save operability of on train and major cables required for safe shutdown.

Expert opinion by Ulrich Witte as former Project Engineer for the Appendix R Program to the Sacramento Utilities District Rancho Seco plant is provided in his Declaration contained in Exhibit FP-7.

Inadequate Justification for Invoking 10 CFR 50.12

The exemption the Applicant has sought would allow use of a fire barrier expected to provide less than 1 hour of fire protection. Stakeholders assert that the grant of this exemption constitutes an abuse of the Commission's discretion and violates the letter and spirit of the Atomic Energy Act of 1954, as amended.

These regulations, §10 CFR 50.12 and Appendix R were promulgated specifically in response to the 1975 Browns Ferry accident.

Brown Ferry continues to provide a particularly dramatic example of how quickly a nuclear plant can be put in jeopardy and how difficult responsive action can be. The Browns Ferry fire burned out of control for some 7 hours with temperatures as high as 1500 degrees Fahrenheit. Within 15 minutes of initiation, a high number of safety-related circuits were destroyed. By the time it was extinguished, 1600 electrical cables, including 628 safety-related circuits needed to shut down the reactor and keep it cool, coolant had been destroyed. In a 1976 report prepared by the Union of

Concerned Scientists, entitled "Browns Ferry: The Regulatory Failure," the investigators noted that thick smoke, the chaos resulting from the loss of control over equipment, and inadequate breathing apparatuses made it difficult for operators to save the plant. The report revealed that the operator's nuclear engineers had stated privately to the investigators "that a potentially catastrophic radiation release from Browns Ferry was avoided by 'sheer luck.'"

Twenty million residents living within 50 miles of Indian Point Units 2 & 3 should not have to depend on "sheer luck". The NRC has the responsibility to maintain reasonable regulations with regard to fire safety protection that will adequately protect public health and safety. Stakeholders assert that a grant of Applicant's request for exemption would abuse the authority granted to the NRC by Congress.

The underlying purpose of Subsection III.G.2 of 10 CFR Part 50, Appendix R, is to ensure that one of the redundant trains necessary to achieve and maintain hot shutdown conditions remains free of fire damage in the event of a fire. This safety margin is an imperative to protect public health and safety. It dramatically reduces the defense-in-depth criteria.

Special Circumstances: One of the special circumstances, described in 10 CFR 50.12(a)(2)(ii), is that the application of the regulation is necessary to achieve the underlying purpose of the rule. The underlying purpose of Subsection III.G.2 of 10 CFR Part 50, Appendix R, is to ensure that one of the redundant trains, necessary to achieve and maintain hot shutdown conditions remains free of fire damage in the event of a fire. As shown, this is not possible given the physical characteristics, including the layout of the cabling in the tunnel. and the material used as insulation.

Based upon consideration of the information in the Applicant's Fire Hazards Analysis, administrative controls for transient combustibles and ignition sources, previously-granted exemptions for this fire zone, and the considerations noted above, it is incorrect for the NRC staff to conclude that the Applicant's exemption request meets the underlying purpose of the rule.

There are numerous options available that do not require unacceptable risks to be placed on the safe operation, and emergency shutdown of Indian Point 2 and Indian Point3, as well as, and protection of the health and safety of the public are available.

There are no special circumstance is present, which would justify allowance the exemption requested by Entergy.

<u>Conclusion</u>

Stakeholders assert that Applicant and the NRC have improperly determined that pursuant the Exemption is authorized by law. The exemption is not authorized by law, as it causes an undue risk to the public health and safety and thwarts the very purpose of the regulation.

Contention Number 2.
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.

Issue Summary:

Congress imposed upon the Nuclear Regulatory Commission rulemaking requirements to implement defenses against twelve distinct threats as contained under a classified documents. The Commission partially codified the Energy Policy Act of 2005 (EPAct) requirements most recently on April 18, 2007, under 10 CFR73.1, 21, 55, 56, and 10 CFR26. This contention raises issues of conformance with the *existing rule*, regardless of the controversy associated with whether the current rule fully implements the Energy Policy Act of 2005 (EPAct).

The Stakeholders assert that the existing rules as currently promulgated is within scope of the license renewal application submitted by Entergy. Yet they are not addressed in the LRA with regard to the Fire Protection Program enhancements necessary for implementation.

In fact, the Applicant has requested and has been granted an exemption to specific federal rules, that actually erodes safety at Indian Point 2 and 3, and increases vulnerability to the facility to a design basis threat that was required to be strengthened by Energy Policy Act of 2005 (EPAct).

The Applicant's LRA fails to comply with applicable law with respect to fire protection. Fire protection is one of the twelve specific components within the DBT rule. This exemption affects the current operating license, and will be carried over into the proposed new superceding license.

The Final Rule Regarding Design Basis Threat and Fire:

Congress also recognized the need for the NRC to conduct a rulemaking to update the DBT regulation in light of the events of September 11, 2001. On August 8, 2005, the President signed into law the Energy Policy Act of 2005, Pub. L. No.109-58, 119 Stat. 594, which mandated that, within 90 days, the NRC "initiate a rulemaking proceeding, including notice and opportunity for public comment, to be completed not later than 18 months after that date, to revise the design basis threats of the Commission." *Id.* § 651, *codified at* 42 U.S.C. § 2210e. The Act specifically listed 12 factors that the NRC had to consider in conducting its rulemaking, including "the events of September 11, 2001," "the potential for attack on facilities by multiple coordinated teams of a large number of individuals," and "the potential for water-based and air-based threats." 42 U.S.C. § 2210e(b).

The NRC published its final rule in the Federal Register on March 19, 2007. 72 FR 12705 (ER 1). Although the Commission made some changes in the language of the proposed rule (adding, for example, a provision requiring defense against the threat of cyber-attacks), the agency made no changes in response to comments that had challenged its refusal to conduct an EIS, its failure to require a defense against attacking forces as large as those assembled by al Qaeda on 9/11, and against the threat of suicide attacks by large aircraft. Indeed, the Commission explicitly declined to require a defense against a force as large as that involved in the 9/11 attacks (72 FR at 12708), and it refused to incorporate any provisions concerning air attacks in the DBT (*id.* at 127 10-1 1).

1. Commission's "Reasonableness" Limit on the Design Basis Threat and the Size of the Attacking Force

Throughout the final rule, the Commission emphasized that a fundamental principle animating the DBT was that it would require a licensee to do no more than defend against attacks that a private security force could reasonably be expected to counter. As the agency put it, "The Commission has determined that the DBTs, as articulated in the rule, are based on adversary characteristics against which a private security force can reasonably be expected to defend." 72 FR at 12713.

The agency provided only one example of what might make it "unreasonable" to expect a private security force to respond to a threat: that there are "legal limitations" on the types of weapons and defensive systems available to private security forces. "Thus," the agency asserted, "it would be unreasonable to establish a DBT that could only be defended against with weapons unavailable to private security forces." *Id.* at 12714.

The NRC did not preclude the potential deliberate use of transient combustibles already available on site, to be use serendipitously to interfere with the safe operation of the facility. In fact, the rule provides that the licensee must assume that the assailant has knowledge of specific target selection and access to transient combustibles. As directed by the Energy Policy Act, the final rule has the principal objective of making the security requirements imposed by the April 29, 2003, DBT orders generically applicable. Although specific details of the revised DBT were not released to the public, in general the final rule:

- clarifies that physical protection systems are required to protect against diversion and theft of fissile material;
- expands the assumed capabilities of adversaries to operate as one or more teams and attack from multiple entry points;
- assumes that adversaries are willing to kill or be killed and are knowledgeable about specific target selection;

- expands the scope of vehicles that licensees must defend against to include water vehicles and land vehicles beyond four-wheel-drive type;
- revises the threat posed by an insider to be more flexible in scope; and
- adds a new mode of attack from adversaries coordinating a vehicle bomb assault with another external assault.

The above reflect the need to enhance the facility against the threat of fire. However, in Entergy's most recent request for an exemption dated August 16, 2007, reducing the one hour rule contained in Appendix R to 10 CFR50 to and unacceptable 24 minutes.

The scenario upon which Entergy gambles, to wit: fire ignition, fire detection, confirmation, determination of proper control acts, fire brigade formation and dispatch, and extinguishment – all in less than 24 minutes – under conditions of high heat, smoke and with electrically energized circuits present, is highly unlikely, and cannot be relied upon as credible. Notably, in addition to putting out the blaze, plant responders would also need to save operability of on train and major cables required for safe shutdown. Under requirements of 10 CFR73.1, a single event, fire in one of the two tunnels, Fire Area ETN-4 (Fire Zones 7A, 60A and 73A) if not extinguished in less than 24 minutes violates safety margins.

CONTENTION No. 3
Fire initiated by a light airplane strike risks penetrating vulnerable structures.

Stakeholders contend that fire initiated by a crash or deliberate strike of an airplane crash at the facility can initiate a fire or serve fires that spread and disable critical safety systems, specifically the above ground cable tunnels. These tunnels are constructed above ground and consist of two foot concrete walls, which are easily breached by a large or even a small aircraft.

Due to the decrease in fire protection standards, and accidental or planned crash into these structures would probably cause a fire or fires, that could not be extinguished with in 24 minutes, thereby cause safe shut down systems to become inoperable, and creating a core melt scenario.

NRC cannot refute the very real fact that a large commercial aircraft commandeered by terrorists flew right past the twin domes of Indian Point on September 11th, 2001. The reports by the Project on Government Oversight (POGO), on December, 2003 Exhibit FP No, 12, the August 9, 2005, CRCS report to Congress by Carl Behrens and Mark Holt, Nuclear Power Plants: Vulnerability to Terrorist Attack Exhibit FP No, 13 and the

Council on Intelligent Energy & Conservation Policy (CIECP) Comments to Proposed Rule 10 CFR 50,72, and 73 regarding Power Reactor Security Requirements at License Nuclear Facilities, filed with the NRC on March 27, 2007 Exhibit FP no. 14 are referred and fully incorporated, as if set forth herein.

In a 2005 updated, report by Carl Behrens and Mark Holt, Nuclear Power Plants: Vulnerability to Terrorist Attack Exhibit FP no. 15 "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 industry has been too slow and that further measures are needed.

There is no justification for jeopardizing national security and the health and safety of the public and violating NEPA - even to the smallest degree - to safeguard corporate profits.

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-demonstrate that the NRC considers such attacks to be reasonably foreseeable for purposes of requiring a NEPA review.

There is no no-fly zone over Indian Point. This presents a clear and significant danger since planes of all shapes and size, including private jets and large commercial planes. There are at least 7 major airports within the 50 miles of Indian Point, including Westchester County Airport, Stewart International Airport, JFK International Airport, La Guardia Airport, and Newark International.

International carriers are planning to use the plane for flights in and out of Kennedy,. In January 2008, Airbus will be flying into Steward Airport, located approximately 9 miles from Indian Point. Airbus's superjumbo A380, the world's largest passenger plane, It has a wingspan almost as long as a football field, it is eight stories tall, and it weighs 118 tons heavier than the Boeing 747, the planes that were used in the terrorist attack on 9/11. "The biggest purchases of Airbus are from the United Arab Emirates., the craft is certified to carry up to 853 — about twice the capacity of the biggest version of the Boeing 747". (March 2007 NYT).

The residents in the Hudson Valley, specifically Rockland County, all of which is within 20 miles of Indian Point, have been recently advised of the FAA's decision to increase air traffic in the region by 600 flights a day.. On average every two to three minutes the noise of aircraft flying overhead will be heard, and danger from an accidental or intantial crash into the vulnerable above ground part of the plant are greatly increased.

Yet the fire protection has been decreased by more than 50%, due to the NRC's improper approval of Entergy's modified Exemption Request.

The Cost Rationale is flawed as found under 10CFR12

The NRC "disagreed" with comments that urged it to make clear that licensees were required to defend against an attacking force *at least* as large as the 19 attackers assembled by al Qaeda on September 11, 2001. *Id.* at 12708.[1] Instead, the NRC stated that the limit on the size of the attacking forces incorporated in the DBT was based on the "reasonableness" concept. The DBT, in the NRC's words, "represents the largest adversary against which the NRC believes private security forces can reasonably be expected to defend." *Id.* at 12714.

The NRC acknowledged that consideration of costs would be unlawful. *See id.* The NRC did not, however, explain how "reasonableness" figured into a limit on the *size* of the attacking force (and hence the size of the defending force) if it was not a cost-based consideration. The Commission also denied that the reasonableness limitation was a violation of its obligation to ensure adequate protection of

[1] These comments did not ask the Commission to say exactly how many attackers it was requiring licensees to defend against, as such a disclosure would create an obvious risk that an attacker would tailor the size of its force to exceed that specified in the rule. Rather, commenters urged the Commission to make clear that the DBT required defense against forces the size of the 9/11 attack groups, but not that it was limited to groups of that size, but its explanation on this point amounted only to the assertion that adequate protection of safety and health somehow followed logically from the reasonableness limit:

the public:

> "The rule text set forth at § 73.1 represents the largest adversary against which the Commission believes private security forces can reasonably be expected to defend. Thus, when the DBT rule is used by licensees to design their site specific protective strategies, the Commission is thereby provided with reasonable assurance that the public health and safety and common defense and security are adequately protected. *Id.*

Elsewhere, the Commission appeared to acknowledge that the defense forces required by the DBT would not be "adequate" if attacked by a force larger than the Commission felt it was "reasonable" to expect a private security force to defend against, but it stated that it was "confident" that the defenders would still try their best if attacked by such a superior force:

> Within this requirement is the expectation that, if confronted by an adversary beyond its maximum legal capabilities, on-site security would continue to respond with a graded reduction in effectiveness. The Commission is confident that a licensee's security force would respond to any threat no matter the size or capabilities that may present itself.

Stakeholders assert that the exemptions and the failure to adequately Indian Point from the threat of a rapidly spreading fire a wholly untenable risk to public health and safety. Approval of this exemption constitutes a violation of the law and the principal mandate of the Atomic Energy Act and violates 10 CFR 73.1.

CONTENTION 4

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.

In the proposed exemption request filed on July 24, 2006, whereby Entergy requested a reduction from 1 hour to not 30 minutes was not inconsequential. But then, the amended request August 16, 2007, to less than 24 minutes and if design modifications were implemented, is a significant change to the exemption request and a substantial reduction in fire protection.

Full-scale fire tests recently performed by the NRC revealed that HemyC, a fire barrier system used to protect cables in electrical raceways in nuclear power plants, does not perform as designed. The outer covering of the barrier can shrink during a fire, opening joints in the material and potentially allowing the fire to damage cables inside. These results show that HemyC does not serve as a fire barrier for the full hour required.

Despite these new test that identified that HemyC could not withstand a fire for more than 24 minutes in certain cable set-us, required to be 1 hour it is still be used at Indian Point 3. The NRC issued Generic Letter 2006-03 in April 2006 to ensure that the affected licensees take appropriate corrective actions.

On August 16, 2007, Entergy notified the NRC that deficient design of the HemyC fire wrap would not withstand the originally proposed exemption of 30 minutes, but for an unknown duration with a best guess of 24 minutes --- and that guessed duration would only be *after plant modifications* were completed. The necessary modifications may remain unimplemented up to December 2008.

There was no public comment period . The changes made to the proposed exemption on August 16, 2007 where never made formally public, and *almost no one noticed* until after the grant. Even the New York State Attorney General's Office who objected on the same day , believed that the exemption was still pending.

Complete and proper analysis of the implications on fire safety caused by the greatly reduced fire standard usually takes months. However, in a matter of a few short weeks the amended exemption request was accepted by the NRC.

The affect of NRC's grant of the October 4, 2007 exemption, are 1) reduction of fire safety parameters by more than 50%; 2) non-compliance by the operator for more than 10 years, is now pardoned, despite long term safety violations; 3) failure to consider public comment; and most importantly, 4) erosion of the time available to detect, respond and extinguish a fire that affects both *power* of emergency core cooling systems and the *controls* for those emergency systems and for normal control of reactor criticality itself.

Stakeholder contend that the NRC improperly granted the exemption request, that in fact is an license amendment, without allowing for public comment. Therefore Stakeholder request a hearing on all the exemption request reduction to 24 minutes.

CONTENTION 5:
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.

In bold violation of promises to Congress to correct deficiencies from a similar material failure – thermolag affecting 79 plants, the NRC instead has accepted deficiencies in fire safety. The current approval of the exemption for Indian Point requiring manual actions to save equipment is unconscionable and fails to adequately protect public health and safety.

The NRC was aware of multiple plants directly defying the present rules regarding fire protection with prima facie evidence in operational procedures of depending on manual actions to save (not repair) essential equipment without exemptions even requested.

In 1993 Congress called for hearings on Fire Protection, to correct problems with a fire-retarding material at nuclear power plants. The Justice Department began a criminal investigation into whether the NRC and the nuclear industry 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 in 1993. Exhibit FP No. 3

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. The current situation with HemyC, unfortunately is reminiscent of Thermo-Lag.

Investigations found Thermo-Lag was approved as a protective barrier in the early 1980s. The NRC staff, however, never conducted independent tests to determine if the material met federal standards.

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 Office of the 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 material in question, Thermo-Lag, was used in 79 nuclear power plants nationwide. .

During a 10 year period 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.

David Williams, Inspector General for the U.S. Nuclear Regulatory Commission, also told lawmakers the NRC " 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 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." He charged that the use of 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.

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."

Stakeholders assert that the issues with regard to the failure of ThermoLag to perform as advertised, put the NRC on notice to adequate perform test on other similar materials, such as HemyC. The NRC subsequently failed to properly test HemyC, used at Indian Point 3.

Stakeholders contend that NRC improperly approved Entergy amended exemption request. Stakeholder further contend that the NRC must order retrofits to bring Indian Point 3 into compliance, not reduce the standards of the regulations to meet non-compliant facilities.

CONTENTION 6.

The NRC routinely violates §51.101(b) in allowing changes to the operating license be done concurrently with the renewal proceedings.

While Stakeholders are trying to prepare Intervenor Contentions to the License Renewal Application (LRA) which was accepted by the NRC on August 2, 2007, Entergy submitted a modified exemption request on August 16, 2007, which was first filed on June 6, 2006.

Without public involvement and in defiance of §51.101(b), approved and published on October 4, 2007

On September 28th, the NRC granted the exemption to fire protection. The NRC did so, without a public comment period or hearing. The NRC claimed the change from 1 hour to 24 minutes of fire protection, was insignificant, and therefore public comment was not necessary.

On October 4, the exemptions was published in the Federal Registry.

This kind of exemption, which constitutes an operating license amendment, requires 6 and 9 months to be fully evaluated, and often more than a year.

On August 16 , 2007 Entergy informed the NRC that the exemption they were requesting was not 30 minutes, but rather only 24 minutes. This was a significant reduction and physically unrealistic to accomplish the necessary analysis and required Safety Evaluation in five short weeks on this brand new issue.

Stakeholders contend that the NRC acted improperly in approved the license amendment/modified exemption request without the required Safety Evaluation. Therefore the exemption must be cancelled.

Stakeholders object to the NRC's grant a finding of no significant hazard with regard to an exemption to the requirements under Federal Rules to be reflected in a forthcoming Safety Evaluation and resulting in an amendment to License No DPR 64 for Indian Point Unit 3, Notice published on October 4, 2007, in the Federal Register. and Stakeholders Petition for Leave to Intervener and Request a Hearing on the above issues, and reopen for consideration the exemption requested due to new, substantial and significant information published on October 4, 2007.

Respectfully submitted by:

Susan Shapiro
Representing:
New York State Assemblyman Richard Brodsky
Westchester Citizen's Awareness Network
Rockland County Conservation Association
Public Health & Sustainable Energy
Beyond Nuclear
Sierra Club – Atlantic Chapter

Reference 3

Reference "3"

Northern Lights Engineering, L.L.C.
71 Edgewood Way, Westville, Connecticut, 06515
Ulrich K. Witte

December 17, 2007

Honorable Annette L. Vietti-Cook
Secretary
United States Nuclear Regulatory Commission
Washington, D.C., 20555-001

Re: Notice of "A new subpartK-Additional Requirements" to include proposed §52.500, "Aircraft Impact Assessment" contained in Federal Register 56308 /Volume 72, No. 191, published October 3rd 2007.

Subject: Comments Regarding Proposed New Rule.

Dear Secretary Vietti-Cook:

I am a consultant in the nuclear power industry and read with interest the notice published in the Fed. Reg. regarding rule making associated with Aircraft Impact Assessment under proposed rule §52.500.

After examining the analysis provided in the Fed. Reg. I am formally providing comments regarding the statutory requirements imposed upon the Nuclear Regulatory Commission. From the analysis of the several statutes that apply when the Commission proposed to codify the Design Basis Threat of airborne sabotage of domestic nuclear facilities it is clear that the NRC has not properly implemented its congressional mandate of implementing regulations governing design of nuclear power plants and that those regulations must by statutory authority be fully promulgated under federal rules or other mechanism with the force of law.

I submit these comments in the attached brief, pointing out that each regulation governing the design of nuclear power plants and any other activity authorized pursuant to the Atomic Energy Act of 1954, 42 U.S.C. §§2011 *et seq.* must address its subject so as to minimize danger to life or property.

Office: 203 389 4564
Mobil: 860 391 1183
Fax: 203 389 6657
Email: ulrich@ulrichwitte.com

Northern Lights Engineering, L.L.C.
71 Edgewood Way, Westville, Connecticut, 06515
Ulrich K. Witte

As drafted the proposed 10 C.F.R. §52.500 does not meet the statutory requirements for regulations governing the design of nuclear facilities. The United States Nuclear Regulatory Commission must withdraw the proposed regulation, amend the proposed regulation so that it conforms to statutory standards and republish it for comment.

Kindest regards,

Ulrich Witte

Office: 203 389 4564
Mobil: 860 391 1183
Fax: 203 389 6657
Email: ulrich@ulrichwitte.com

Before the

UNITED STATES NUCLEAR REGULATORY COMMISSION

In the Matter of	)	
Proposed new Subpart K --	)	
"Additional Requirements"	)	
and proposed 10 C.F.R. §52.500	)	Docket No. RIN - 3150 - AI19
"Aircraft Impact Assessment"	)	

COMMENTS

POINTING OUT THAT
REGULATIONS GOVERNING DESIGN OF NUCLEAR POWER PLANTS MUST MINIMIZE DANGER TO LIFE OR PROPERTY

I. Summary

After September 11, 2001 the ability of terrorists to strike through the air as well as on land and over water is beyond dispute. If evidence that terrorist can use means other than aircraft is needed, the missile and mortar attacks on our troops in Iraq and Afghanistan are more than sufficient. During a taped interview shown September 10, 2002, on Arab TV Station Al-Jazeera, contained statements that Al

Qaeda initially planned to attack a nuclear plant in its 2001 attack sites.[1] For these reasons I submit these comments pointing out that each regulation governing the design of nuclear power plants and any other activity authorized pursuant to the Atomic Energy Act of 1954, 42 U.S.C. §§2011 *et seq.* ("1954 Atomic Energy Act") must address its subject so as to minimize danger to life or property.[2] As drafted the proposed 10 C.F.R. §52.500 does not meet the statutory requirements for regulations governing the design of nuclear facilities. The United States Nuclear Regulatory Commission ("NRC") must withdraw the proposed regulation, amend the proposed regulation so that it conforms to statutory standards and republish it for comment.

II. INTRODUCTION

The United States has over a hundred active and an additional number of

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1 Congressional Research Service Report for Congress—Nuclear Power Plants: Vulnerability to Terrorist Attack, August 9, 2005.

2 42 U.S.C. §2201(i)(3)("General provisions - (i) Regulations or orders. prescribe such regulations or orders as it may deem necessary ... **(3) to govern any activity authorized pursuant to this Act [*42 USC §§ 2011* et seq.], including standards and restrictions governing the design, location, and operation of facilities used in the conduct of such activity, in order to protect health and to minimize danger to life or property" (emphasis added)**)

retired nuclear power plants with active associated spent fuel pools.[3] These plants and pools containing enormous amounts of radioactive and toxic materials that a successful terrorist attack could release into the environment. Many of these facilities are on or close to the nation's shores or borders. Some, e.g., Indian Point Energy Center's two operating reactors, a closed reactor and three spent fuel pools, are close to major population centers.[4] A successful air attack on Indian Point could cause horrific physical injury to many of the 20 million people who live within 50 miles of that facility and enormous economic loss for individuals, the nation and the entire world economy.

The 1954 Atomic Energy Act assigns the NRC responsibility for ensuring the safety of our nuclear facilities. This duty includes establishing standards for defending these facilities against sabotage by terrorists.

In part the NRC establishes antiterrorist and other nuclear power plant safety standards by issuing regulations under authority granted in the Act. On October 3, 2007 the NRC published in the Federal Register a proposed new regulation, 10

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[3] *See, e.g.*, NUREG-1350, Volume 19, 2007 – 2008 Information Digest, Appendices A: U.S. Commercial Nuclear Power Reactors & B: U.S. Commercial Nuclear Power Reactors Formerly Licensed to Operate (Permanently Shut Down).

[4] The three Indian Point nuclear power plants and their three associated spent fuel pools are on the east bank of the Hudson close to vital parts of New York City's water supply and about 30 miles from Times Square.

CFR §52.500, intended to make a few of the anticipated new nuclear power plants somewhat more secure against aircraft deliberately crashed into them by terrorists.[5]

The actual number of plants likely to be affected by this regulation is about eight, leaving the remaining fleet of 125 operating or closed facilities unprotected from air attacks and most of the new generation reactors beyond the scope of this intended rule as well.

The proposed rule does not mitigate a single current threat—leaving one wondering why this rulemaking is prioritized above other codification requirements directed by Congress. For example, the House Appropriations Committee in preparing the House version of the FY2006 Energy and Water development bill (H.R. 2419, H. Rept 109-86) states: "The Committee expects the NRC to redouble its efforts to address the NAS identified deficiencies [Report by the National Academy of Sciences findings released April 6, 2005] and to ***direct, not request industry to take prompt corrective action,"***

In its notice the NRC invited comments on the proposed regulation.

THE PROPOSED RULE

The NRC's Federal Register notice states that the purposes of the proposed 10 CFR §52.500 are to provide nuclear power plants an "enhanced level of

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[5] 72 Fed. Reg. 56,287 - 56,308 (October 3, 2007).

protection,"[6] improve knowledge of ways to avoid or mitigate the threat of aircraft impacts on such plants,[7] and increase public confidence in nuclear power.[8] The means for achieving these goals would be to have applicants for new generic certification or approval of plant or reactor designs and some nuclear power plant construction permits prepare an "aircraft impact assessment."[9] Specifically, the proposed rule would require applicants for (1) "new standard design certifications that do not reference a standard design approval," (2) "new standard design approvals," (3) "combined licenses that do not reference a standard design certification, standard design approval, or manufactured reactor; and (4) "new manufacturing licenses that do not reference a standard design certification or standard design approval"[10] to (a) analyze their plant or reactor designs for ways to change those designs so that a plant built with the design changes would be less

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6 *Id.* at 56,288.

7 *Id.* at 56,302.

8 *Id.* at 56,306. It is unclear whether NRC promotion of public confidence in nuclear power is consistent with the regulatory responsibilities assigned the NRC when Congress abolished the Atomic Energy Commission ("AEC") and transferred the AEC's nuclear power promotion authority to what is now the U.S. Department of Energy. *See, e.g.,* Energy Reorganization Act of 1974, P. L. 93-438.

9 *Id.* at 56,287.

10 *Ibid.*

likely to release significant radiation if a terrorist crashes a commercial airliner into the plant, and (b) report to the NRC which of the identified potential design improvements the applicant actually adopts.[11]

According to the NRC, the proposed rule would likely improve the security of about eight new nuclear power plants over the next 20 years[12] but all operating and retired nuclear power plants, and an unknown number of new plants built using designs with "standard design certification," "an approval standard design approval," or a "licensed" manufactured nuclear power plant [,] would be exempt from the proposed regulation.[13]

The aircraft impact assessments the proposed rule would require would be based solely on potential for damage from aircraft impacts even though terrorists can use other weapons, e.g., missiles, mortars or artillery.[14] The Federal Register notice does not explain why air attacks by means other than aircraft are ignored.

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[11] *Id. at* 56,292.

[12] *Id.* at 56,303 - 56,305 (8 plants using new standard design certifications; none using a new approved standard design; 1 with a combined license not referencing a standard design certification, a standard design approval or a licensed manufactured reactor; and 1 using a licensed manufactured reactor but not a standard design certification or an approved standard design).

[13] *See, e.g., Id.* at 56,290 - 56,291.

[14] *See, e.g., id.* at 56,287.

Indeed, the notice contains no reference to any air attack threat other than aircraft.

In the Federal Register notice the NRC describes the aircraft to be used as the basis for impact assessments in only the most general terms; this "aircraft's" characteristics are to be those of "a large, commercial aircraft used for long distance flights in the United States, with aviation fuel loading typically used in such flights."[15]

Whatever characteristics the NRC chooses for its generic assessment-basis aircraft, once adopted these characteristics would not change in response to either actual threat assessments or the evolution of commercial aircraft.[16]

Implementation of whatever potential security improvements the application of the proposed regulation would identified would be discretionary.[17] In its Federal Register notice the NRC repeatedly indicates that the aircraft impact assessment would be used to identify potential ways to "avoid or mediate" the damage that a "beyond-design-basis threat" could cause and that nuclear power plant licensees

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[15] *See, e.g., id.* at 56,291 - 56,292. The NRC indicates that the detailed characteristics of the assessment-basis aircraft will be available to parties that have a specific need for this information.

[16] *Id. at* 56,291.

[17] *See, e.g., id.* at 56,288.

are not required to defend against such threats.[18]

Although implementation of any identified security improvement would be discretionary, the NRC indicates that the proposed regulation would result in "an enhanced level of protection beyond ... adequate protection"[19] and "improve[d] knowledge ... of the effects of the impact of a large, commercial aircraft on" nuclear power plants.[20] Indeed, the NRC states:

> The proposed regulatory action ***would reduce*** the risk that public health will be affected by the release of radioactive materials to the environment from the impact of a large, commercial aircraft on a nuclear power plant.

...

> The proposed regulatory action ***would reduce*** the risk that occupational health will be affected by the release of radioactive materials to the environment from the impact of a large, commercial aircraft on a nuclear power plant.
>
> The proposed regulatory action ***would reduce*** the risk that offsite property will be affected by the release of radioactive materials to the environment from the impact of a large, commercial aircraft on a nuclear power plant.
>
> The proposed regulatory action ***would reduce*** the risk that onsite property will be affected by the release of radioactive materials to the environment from the impact of a large, commercial aircraft on a nuclear power plant.[21]

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18 *See, e.g., id. at* 56,292.

19 *Id.* at 56,288 (October 3, 2007).

20 *Id.* at 56,302 (October 3, 2007).

21 *Id.* at 56,302.

(emphasis added)

How analysis alone is certain to improve nuclear power plant security the Federal Register notice does not say.

III. COMMENTS

In addition to being of questionable effectiveness, the proposed 10 CFR §52.500 does not comply with the legal requirement set out in the 1954 Atomic Energy Act for regulations governing the design of nuclear power plants. The current proposal must be revised to take into account the comments set out below, then renoticed for comment.

a. <u>The 1954 Atomic Energy Act statutory standard for the proposed regulation</u>. The 1954 Atomic Energy Act directs that regulations governing the design, location, and operation of nuclear power plants and other such facilities "minimize danger to life or property."[22] That is, whatever control or guidance the NRC provides through means other than regulations or thorough regulations that do not govern "activity authorized pursuant to the Act,"[23] regulations that do govern activity the Act authorizes must provide the maximum protection for life

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[22] 42 USC §2201(i)(3).

23 *See, e.g., 10 CFR Part 5* - **Nondiscrimination on the basis of sex in education programs or**

and property possible given the subject of the regulation.

b. <u>The proposed regulation's 1954 Atomic Energy Act deficiencies</u> The proposed 10 CFR §52.500 falls short of the requirements of the 1954 Atomic Energy Act by (1) covering only a portion of the nuclear power plants and other threatened facilities, (2) not addressing air attack threats other than aircraft, (3) limiting the characteristics of the threat to be used in aircraft impact assessments, (4) ignoring changes in air attack threats and developments in commercial aircraft, (5) limiting the security improvements sought, and (6) relying solely on voluntary implementation of identified security improvements.

1. Requiring threat assessments for all nuclear power plants and related facilities would maximize the increase in security possible from such assessments.

As indicated above, in its current form the proposed regulation would exempt existing nuclear power plants, new nuclear power plants that meet certain criteria and their associated spent fuel pools from aircraft impact assessments. Such exemptions are inconsistent with the requirements of 42 USC §2201(i)(3) in that the proposed regulation would produce its maximum improvement in nuclear facility security if a threat assessment were performed for every such facility. In contrast to its statutory obligations the NRC proposal here is that about 8 facilities have threat assessments while over 100 other plants operate without analysis. Moreover, adopting 10 CFR §52.500 as proposed would increase the terrorist

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activities receiving Federal financial assistance.

threat to unassessed plants and those who live near them. Labeling one set of nuclear power plants as better protected would in effect paint bull's-eyes on the unassessed plants. Such a result is inconsistent with the legal requirements for regulations governing nuclear power plant design.

2. Examining all means of air attack would maximize the increase in security possible from assessing airborne threats.

For reasons not explained in the Federal Register notice the NRC limits the proposed new regulation to the assessment of the potential consequences of aircraft crashes. While an obvious threat after 9/11, aircraft are not the only weapon terrorist can use to attack nuclear power plants through the air. At a minimum, missiles, mortars and artillery can be used in air attacks. Unless the NRC can explain why addressing only one air attack threat is consistent with maximizing the security of nuclear power plants, any regulation addressing one air attack threat must address all.

3. Basing aircraft impact assessments on the largest commercial aircraft used on intercontinental routes would maximize the increase in security possible from assessing air attack threats.

The NRC proposes to model its assessment-basis aircraft characteristics on a "large, commercial aircraft used for long distance flights in the United States, with aviation fuel loading typically used in such flights."[24] The model the NRC poses would not produce the maximum security increase possible. Instead the assessments must be based on the larger aircraft that fly intercontinental routes. At least sixty existing nuclear power plants are on or near our coasts and thus at risk of being hit by one of the larger aircraft.

Some aircraft used for intercontinental service are significantly larger than those on domestic routes. For example, Boeing states that its 747-ER, a model commonly used for intercontinental flights, has a maximum take off weight of about 900,000 pounds and a maximum fuel load of about 64,000 gallons of kerosene.[25] In contrast, the Boeing 767's hijacked on domestic flights and crashed into the World Trade Center had maximum takeoff weights and fuel loads of about 450,000 pounds and 24,000 gallons,[26] and the domestic workhorse Boeing 737 has maximum takeoff weights and fuel loads of about 145,000 pounds and 7,000 gallons.[27] Given the potential for 747-size air crashes at nuclear power plants on or

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[24] *See, e.g., id.* at 56,291 - 56,292. The NRC indicates that the detailed characteristics of the assessment-basis aircraft will be available to parties that have a specific need for this information.

[25] *See, e.g.,* http://www.boeing.com/commercial/747family/pf/pf_400er_prod.html.

[26] *See, e.g.,* http://www.boeing.com/commercial/767family/pf/pf_400prod.html

[27] *See, e.g.,* http://www.boeing.com/commercial/737family/pf/pf_600tech.html

near our costs coasts, maximization of the security improvements derived from 10 CFR §52.500 requires assessments based on 747-like characteristics.

4. To maximize the increase in security possible from assessing air attack threats, aircraft impact assessments must take into consideration changes in the air attack threat and commercial aircraft developments.

The NRC poses to freeze the assessment-aircraft characteristics used in 10 CFR §52.500. Such an approach is inconsistent with the statutory requirement for regulations involving nuclear facility design to maximize security for life and property. Whatever air attack threat characteristics are at the time of a given threat assessment, those characteristics may change. New air attacks threats must be taken into consideration if the regulation is to continue to maximize security. In particular, the characteristics of commercial aircraft in common use are likely to change over time. Indeed, the potential for an order of magnitude increase in the threat commercial aircraft pose is visible in the efforts to make the Airbus 380 commercially viable.[28] At a minimum the NRC must provide for periodic reexamination of the assessment-aircraft characteristics and modification of the characteristics when a significant change in the air attack threat is identified.

5. To maximize the increase in security possible from assessing air attack threats, such assessment must look for ways to prevent air attacks from reaching nuclear facilities.

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[28] *See, e.g.,* http://www.airbus.com/en/aircraftfamilies/a380/index2.html.

One stated purpose for the aircraft impact assessment that 10 CFR §52.500 would institute is the identification of the means to avoid or mitigate the consequences of an aircraft's crashing into a nuclear power plants or associated facilities. To maximize the security improvements from such assessments the assessments must include a search for ways to prevent an aircraft or other air attack from hitting a facility or vital equipment if a hit cannot be completely prevented.

There are both active and passive defenses against air attacks. Active air defenses, such as antiaircraft missiles and other weapons exclusively available to the military, the NRC properly excluded from the Design Basis Threat regulation[29] and proposes to exclude here.[30]

However, there is no bar to nuclear power plant licensees' building effective passive air defenses such as concrete covers and metal barriers. For example, a properly designed and located metal barrier could stop an aircraft before it strikes a plant and a reinforced concrete cover for a vital nuclear power plant component could both detonate mortar shells before the shells reach the component and protect the component from any resulting explosions.

Despite the obvious value of using passive defenses to frustrate air attacks the NRC appears to base 10 CFR §52.500 on an assumption that the starting point of an

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[29] 10 CFR sec. 73.1.

[30] *Id.* at 56,288.

aircraft impact assessment is the impact of the airplane on a nuclear power plant. If so, the proposed regulation would forgo passive air defense and thereby violate 42 USC §2201(i)(3)'s requirement that regulations governing the design of nuclear facilities maximize protection of life and property.

The NRC's "enemy of the United States" Rule, 10 CFR §50.13, [31] cited in the Federal Register notice in this proceeding as justification for leaving air attacks out of the Design Basis Threat, does not permit leaving passive air defenses out of 10 CFR §52.500.[32] The intent of the "enemy of the United States" Rule is to excuse nuclear facility licensees from having to design or build features for the specific purpose of protecting their facilities against "the effects of (a) attacks and destructive acts, including sabotage, directed against the facility by an enemy of the United States, whether a foreign government or other person, or (b) use or deployment of weapons incident to U.S. defense activities."[33] There are several reasons why the Rule is not applicable to 10 CFR §52.500's treatment of passive air

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31 10 CFR Part 52, to which 10 CFR §52.500 would be added, has an almost identical provision, 10 CFR §52.10. The *Federal Register* here notice makes no mention of 10 CFR §52.10.

32 The "enemy of the United States" Rule also does not justify leaving air attacks out of the Design Basis Threat, for most of the same reasons the Rule is irrelevant to 10 CFR §52.500.

33 10 CFR Part 52, to which 10 CFR §52.500 would be added, has an almost identical provision, 10 CFR §52.10. The Federal Register notice makes no mention of 10 CFR §52.10.

defenses. First, the obligation for nuclear facility design regulations to maximize protection for life and safety is statutory and thus trumps any regulation. Secondly, the "enemy of the United States" rule is cite here as justification for leaving air attacks out of the Design Basis Threat, a regulation that is not under consideration in this proceeding. Thirdly, the attempt to shoehorn the Rule into this proceeding by asserting that crashing an aircraft into a nuclear facility is "in the nature of an attack by an enemy of the United States" fails because the analogy overreaches; by its explicit terms the Rule is limited to (a) acts by an enemy of the United States and (b) use or deployment of weapons incident to U.S. defense activities. The Rule would have to be amended before it would cover acts that are "like" the enumerated acts. Finally, if crashing an aircraft into a nuclear facility qualifies as a threat that the "enemy of the United States" Rule allows nuclear facility licensees to ignore, the NRC's authority to require aircraft impact assessments goes away.[34] What justifies ignoring an act would also justify ignoring an order to examine that act.

Mandatory aircraft impact assessments can coexist with the "enemy of the United States" Rule. Issued in 1967 during the Cold War, the Rule addressed a world where the external threat to nuclear power plants and facilities was military

34 If an aircraft crash is sufficiently "like" an attack by an "enemy of the United States to invoke the "enemy of the United Staes Rule, then the NRC's justification for including land and waterborne threats in the Design Basis Threat is also suspect. A land attack by a group of armed terrorists is like an infantry attack ; waterborne attacks are what navy's do.

action by the Soviet Union and its surrogates.35 Nuclear power plant owners can't defend against bombers, guided missile cruisers or other heavy weapons nation states have, much less the number of attackers a nation state can field. Terrorists are another matter. While the 9/11 attack caused enormous destruction, all but the tiniest nation state has military forces with destructive capability that dwarfs that of the four aircraft hijacked.

6. To comply with the 1954 Atomic Energy Act the proposed regulation must required that identified security improvements be installed.

All the assessment in the world will not improve the security of even one nuclear power plant if the improvements are totally discretionary and the plant owners choose not to install the designated ,improvements. Thus there is no guarantee that a purely voluntary implementation will maximize the security improvements. To comply with 42 USC §2201(i)(3) the final 10 CFR §52.500 must require that nuclear licensees install the security improvements that the assessments identify.

CONCLUSION

[35] *See, e.g., Siegel v. Atomic Energy Commission*, 400 F.2d 778 (D.C. Cir. 1968) (Atomic Energy Commission not required to consider whether a proposed nuclear power plant in Florida would be vulnerable to Cuban military attack).

The NRC's ignoring the potential for air attacks on nuclear power plants when installing passive defenses could make such plants safer from air attacks has never made any sense as policy. Here the NRC at lasts admits that air attacks should be taken into consideration, but proposes to do so in a virtually useless way. This continued lack of bona fide action doesn't make any sense, and as shown above is also illegal. The NRC should withdraw 10 CFR §52.500 as proposed, amend it consistent with the comments set out above, and renotice a proposed rule that will make the public safer from terrorist attacks.

Reference 4

Reference 4

United States Government Accountability Office

GAO

Testimony

Before the Subcommittee on Clean Air, Climate Change, and Nuclear Safety, Committee on Environment and Public Works, U.S. Senate

For Release on Delivery
Expected at 10:00 a.m. EDT
Thursday, May 26, 2005

NUCLEAR REGULATORY COMMISSION

Challenges Facing NRC in Effectively Carrying Out Its Mission

Statement of Jim Wells, Director
Natural Resources and Environment

GAO
Accountability * Integrity * Reliability

GAO-05-754T

GAO
Accountability Integrity Reliability

Highlights

Highlights of GAO-05-754T, a testimony before the Subcommittee on Clean Air, Climate Change, and Nuclear Safety, Committee on Environment and Public Works, U.S. Senate

Why GAO Did This Study

The Nuclear Regulatory Commission (NRC) has the regulatory responsibility to, among other things, ensure that the nation's 103 commercial nuclear power plants are operated in a safe and secure manner. While the nuclear power industry's overall safety record has been good, safety issues periodically arise that threaten the credibility of NRC's regulation and oversight of the industry.

Recent events make the importance of NRC's regulatory and oversight responsibilities readily apparent. The terrorist attacks on September 11, 2001, focused attention on the security of facilities such as commercial nuclear power plants, while safety concerns were heightened by shutdown of the Davis-Besse nuclear power plant in Ohio in 2002, and the discovery of missing or unaccounted for spent nuclear fuel at three nuclear power plants.

GAO has issued a total of 15 recent reports and testimonies on a wide range of NRC activities. This testimony (1) summarizes GAO's findings and associated recommendations for improving NRC mission-related activities and (2) presents several cross-cutting challenges NRC faces in being an effective and credible regulator of the nuclear power industry.

www.gao.gov/cgi-bin/getrpt?GAO-05-754T.

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 or wellsj@gao.gov.

May 26, 2005

NUCLEAR REGULATORY COMMISSION

Challenges Facing NRC in Effectively Carrying Out Its Mission

What GAO Found

GAO has documented many positive steps taken by NRC to advance the security and safety of the nation's nuclear power plants. It has also identified various actions that NRC needs to take to better carry out its mission. First, with respect to its security mission, GAO found that NRC needs to improve security measures for sealed sources of radioactive materials — radioactive material encapsulated in stainless steel or other metal used in medicine, industry, and research–which could be used to make a "dirty bomb." GAO also found that, although NRC was taking numerous actions to require nuclear power plants to enhance security, NRC needed to strengthen its oversight of security at the plants. Second, with respect to its public health and safety, and environmental missions, GAO found that NRC needs to conduct more effective analyses of plant owners' funding for decommissioning to ensure that the significant volume of radioactive waste remaining after the permanent closure of a plant are properly disposed. Further, NRC needs to more aggressively and comprehensively resolve issues that led to the shutdown of the Davis-Besse nuclear power plant by improving its oversight of plant safety conditions. Finally, NRC needs to do more to ensure that power plants are effectively controlling spent nuclear fuel, including developing and implementing appropriate inspection procedures.

GAO has identified several cross-cutting challenges affecting NRC's ability to effectively and credibly regulate the nuclear power industry. Recently, NRC has taken two overarching approaches to its regulatory and oversight responsibilities. These approaches are to (1) develop and implement a risk-informed regulatory strategy that targets the most important safety-related activities and (2) strike a balance between verifying plants' compliance with requirements through inspections and affording licensees the opportunity to demonstrate that they are operating their plants safety. NRC must overcome significant obstacles to fully implement its risk-informed regulatory strategy across agency operations, especially with regards to developing the ability to identify emerging technical issues and adjust regulatory requirements before safety problems develop. NRC also faces inherent challenges in achieving the appropriate balance between more direct oversight and industry self-compliance. Incidents such as the 2002 shutdown of the Davis-Besse plant and the unaccounted for spent nuclear fuel at several plants raise questions about whether NRC has the risk information that it needs and whether it is appropriately balancing agency involvement and licensee self-monitoring. Finally, GAO believes that NRC will face challenges managing its resources while meeting increasing regulatory and oversight demands. NRC's resources have already been stretched by the extensive effort to enhance security at plants in the wake of the September 11, 2001, terrorist attacks. Pressure on NRC's resources will continue as the nation's fleet of plants age and the industry's interest in expansion grows, both in licensing and constructing new plants, and re-licensing and increasing the power output of existing ones.

Mr. Chairman and Members of the Subcommittee:

I am pleased to be here today to participate in the Subcommittee's oversight hearing on the Nuclear Regulatory Commission (NRC). NRC has the regulatory responsibility to ensure that the nation's 103 operating commercial nuclear power plants are operated in a safe and secure manner. These plants provide about 20 percent of the country's electricity, but safety of their operations is paramount, given the potentially devastating effects of a nuclear accident. While the nuclear power industry's overall safety record has been good, safety issues periodically arise that raise questions about NRC's regulation and oversight of the industry and challenge its credibility for guaranteeing the safety of the nation's aging fleet of nuclear power plants. NRC plays an important role in protecting public health and the environment through its regulation of the nuclear power industry and other civilian use of nuclear material, and we commend the Subcommittee for holding this hearing.

NRC was formed in 1975, to regulate the various commercial and institutional uses of nuclear energy, including nuclear power plants. NRC's mission is to regulate the nation's civilian use of nuclear material to ensure adequate protection of public health and safety, to promote the common defense and security, and to protect the environment. NRC's activities include, among other things, licensing nuclear reactors (including license transfers and operating experience evaluation), reviewing plant safety procedures, imposing enforcement sanctions for violations of NRC requirements, and participating in homeland security efforts (including threat assessment, emergency response, mitigating strategies, security inspections, and force-on-force exercises). NRC also has regulatory oversight for the decommissioning of nuclear reactors, including accumulating sufficient funds to carry out decommissioning, and for the interim storage of spent nuclear fuel — the used fuel periodically removed from reactors in nuclear power plants.

The importance of NRC's regulatory and oversight responsibilities is made readily apparent by recent events. The terrorist attacks on September 11, 2001, and the subsequent discovery of nuclear power plants on a list of possible terrorist targets have focused attention on the security of the nation's commercial nuclear power plants. Safety concerns were heightened by the discovery of a pineapple-sized cavity in the carbon steel reactor vessel head, and subsequent 2-year shutdown, of the Davis-Besse nuclear power plant in Ohio in 2002. Additional safety concerns were raised by the discovery of missing or unaccounted for spent nuclear fuel at three nuclear power plants. Further, the decommissioning of some of the nations' aging nuclear power plants raises the issue of whether NRC is ensuring that plant owners are accumulating sufficient funds for decommissioning plants in a way that best protects public health, safety, and the environment.

Over the past 2 years, we have issued a total of 15 reports and testimonies on a wide range of NRC activities. (These reports are listed in Appendix I). While our work has primarily focused on identifying ways that NRC can strengthen its regulation and oversight of the nuclear power industry, we have documented a number of productive steps NRC has taken to improve its mission-related activities. One example is the substantial effort that NRC has made in working with the industry to enhance security at nuclear power plants since the September 11, 2001, terrorist attacks. Another example is NRC's considerable effort to analyze what went wrong at the Davis-Besse plant in 2002, and to incorporate the lessons learned into its processes. Today, my testimony will briefly summarize our recently completed NRC work. Specifically, this testimony (1) summarizes GAO's findings and associated recommendations for improving NRC mission-related activities and (2) provides some observations on cross-cutting challenges that NRC faces in being an effective and credible regulator of the nuclear power industry.

This testimony is based on seven of our recently issued reports. The other eight reports either address issues for which NRC is not the primary federal agency – such as radioactive waste disposal and nuclear nonproliferation — or concern internal NRC administrative matters — such as fee recovery and information technology management. We did not perform additional audit work in preparing this testimony. The work for our previously issued reports was conducted in accordance with generally accepted government auditing standards.

Summary

While NRC has improved its operations in a number of ways in recent years, GAO believes that the agency needs to take a number of additional actions to better fulfill its mission of ensuring that the nation's nuclear power plants and other civilian users of nuclear material operate in a safe and secure manner. First, operations related to NRC's security mission need to be improved. Specifically, we found that NRC has not developed adequate security measures for sealed sources of radioactive materials — radioactive material encapsulated in stainless steel or other metal used in medicine, industry, and research — which could be used to make a "dirty bomb." We also found that despite taking numerous actions to respond to the heightened risks of a terrorist attack, NRC's oversight of physical security at the nation's commercial nuclear power plants could be strengthened. Second, operations related to NRC's public health and safety, and environmental missions need to be improved. Specifically, we found that NRC's analyses of plant owners' contributions of funds for the decommissioning of nuclear power plants, and its processes for acting on reports that show insufficient funds, do not ensure that the significant radioactive waste hazards that exist following the permanent closure of a nuclear power plant will be properly addressed. Further, we found that the issues surrounding the shutdown of the Davis-Besse power plant reveal important weaknesses in NRC's oversight of the safety of nuclear power plant operations. Finally, we found that NRC has not taken adequate steps to ensure that power plants are effectively controlling spent nuclear fuel, including developing and implementing appropriate inspection procedures to verify plants' compliance with NRC requirements.

NRC faces several cross-cutting challenges in being an effective and credible regulator of the nuclear power industry. In response to the agency's limited resources and its desire to reduce the regulatory burden and cost on plants, NRC is taking two overarching approaches to meeting its regulatory and oversight responsibilities: (1) developing and implementing a risk-informed regulatory strategy that targets industry's most important safety-related or safety-significant activities, and (2) striking a balance between verifying plants' compliance with requirements through inspections and affording licensees the opportunity to demonstrate that they are operating their plants safely. We believe that NRC must overcome significant obstacles in implementing its risk-informed regulatory strategy across the agency, especially with regards to developing the ability to identify emerging technical issues and adjust regulatory requirements before safety problems develop. We also believe that NRC faces inherent challenges in balancing oversight and industry self-compliance, especially with regards to positioning the agency so it is able to identify diminishing performance at individual plants before they become a problem. Incidents such as the 2002 shutdown of the Davis-Besse plant and the unaccounted for spent nuclear fuel at several plants raise questions about whether NRC has the risk information that it needs and whether it is appropriately balancing agency involvement and licensee self-monitoring. Finally, we believe that NRC will face challenges managing its resources while meeting increasing regulatory and oversight demands. NRC's resources have already been stretched by the extensive effort to enhance security at plants in the wake of the September 11, 2001, terrorist attacks. Pressure on NRC's resources will continue as the nation's fleet of plants age and the industry's interest in expansion grows, both in licensing and constructing new plants, and re-licensing and increasing the power output of existing ones.

Regulatory and Oversight Functions Vital to NRC's Mission Need to be Improved

Our recent analyses of NRC programs identified several areas where NRC needs to take action to better fulfill its mission and made associated recommendations for improvement. With respect to NRC's security mission, we found that the security of sealed radioactive sources and the physical security at nuclear power plants need to be strengthened. With respect to its public health and safety, and environmental missions, we found several shortcomings that need to be addressed. NRC's analyses of plant owners' contributions could be improved to better ensure that adequate funds are accumulating for the decommissioning of nuclear power plants. By contrast, we found that NRC is ensuring that requirements for liability insurance for nuclear power plants owned by limited liability companies are being met. Further, to ensure the safety of nuclear power plants NRC must more aggressively and comprehensively resolve oversight issues related to the shutdown of the Davis-Besse plant. Finally, NRC's methods of ensuring that power plants are effectively controlling spent nuclear fuel need to be improved.

Operations Related to NRC's Security Mission Could Be Improved

In August 2003, we reported on federal and state actions needed to improve security of sealed radioactive sources.[1] Sealed radioactive sources, radioactive material encapsulated in stainless steel or other metal, are used worldwide in medicine, industry, and research. These sealed sources could be a threat to national security because terrorists could use them to make "dirty bombs." We were asked among other things to determine the number of sealed sources in the United States. We found that the number of sealed sources in use today in the United States is unknown primarily because no state or federal agency tracks individual sealed sources. Instead, NRC and the agreement states[2] track numbers of specific licensees. NRC and the Department of Energy (DOE) have begun to examine options for developing a national tracking system, but to date,

[1]GAO: *Nuclear Security Federal and State Action Needed to Improve Security of Sealed Radioactive Sources*, GAO-03-804 Washington, D.C.: Aug. 6, 2003.

[2]Agreement states are the 33 states that have entered into an agreement with the NRC under subsection 274(b) of the Atomic Energy Act (AEA) under which NRC relinquishes to the states portions of its regulatory authority to license and regulate source, byproduct, and certain quantities of special nuclear material.

this effort has had limited involvement by the agreement states. NRC had difficulty locating owners of certain generally licensed devices it began tracking in April 2001, and has hired a private investigation firm to help locate them. Twenty-five of the 31 agreement states that responded to our survey indicated that they track some or all general licensees or generally licensed devices, and 17 were able to provide data on the number of generally licensed devices in their jurisdictions, totaling approximately 17,000 devices. GAO recommended that NRC (1) collaborate with states to determine the availability of the highest risk sealed sources, (2) determine if owners of certain devices should apply for licenses, (3) modify NRC's licensing process so sealed sources cannot be purchased until NRC verifies their intended use, (4) ensure that NRC's evaluation of federal and state programs assesses the security of sealed sources, and (5) determine how states can participate in implementing additional security measures. NRC disagreed with some of our findings.

In September 2003, we reported that NRC's oversight of security at commercial nuclear power plants needed to be strengthened.[3] The September 11, 2001, terrorist attacks intensified the nation's focus on national preparedness and homeland security. Among possible terrorist targets are the nation's nuclear power plants which contain radioactive fuel and waste. NRC oversees plant security through an inspection program designed to verify the plants' compliance with security requirements. As part of that program, NRC conducted annual security inspections of plants and force-on-force exercises to test plant security against a simulated terrorist attack. GAO was asked to review (1) the effectiveness of NRC's security inspection program and (2) legal challenges affecting power plant security. At the time of our review, NRC was reevaluating its inspection program. We did not assess the adequacy of security at the individual plants; rather, our focus was on NRC's oversight and regulation of plant security.

We found that NRC had taken numerous actions to respond to the heightened risk of terrorist attack, including interacting with the Department of Homeland Security and issuing orders designed to increase security and improve defensive barriers at plants. However, three aspects of NRC's security inspection program reduced the agency's effectiveness in overseeing security at commercial nuclear power plants. First, NRC

[3]GAO: *Nuclear Regulatory Commission: Oversight of Security at Commercial Nuclear Power Plants Needs to Be Strengthened*, GAO-03-752 (Washington, D.C.: Sept. 4, 2003).

inspectors often used a process that minimized the significance of security problems found in annual inspections by classifying them as "non-cited violations" if the problem had not been identified frequently in the past or if the problem had no direct, immediate, adverse consequences at the time it was identified. Non-cited violations do not require a written response from the licensee and do not require NRC inspectors to verify that the problem has been corrected. For example, guards at one plant failed to physically search several individuals for metal objects after a walk-through detector and a hand-held scanner detected metal objects in their clothing. These individuals were then allowed unescorted access throughout the plant's protected area. By extensively using non-cited violations for serious problems, NRC may overstate the level of security at a power plant and reduce the likelihood that needed improvements are made. Second, NRC did not have a routine, centralized process for collecting, analyzing, and disseminating security inspections data to identify problems that may be common to plants or to provide lessons learned in resolving security problems. Such a mechanism may help plants improve their security. Third, although NRC's force-on-force exercises can demonstrate how well a nuclear plant might defend against a real-life threat, several weaknesses in how NRC conducted these exercises limited their usefulness. Weaknesses included (1) using more personnel to defend the plant during these exercises than during normal operations, (2) using attacking forces that are not trained in terrorist tactics, and (3) using unrealistic weapons (rubber guns) that do not simulate actual gunfire. Furthermore, at the time, NRC has made only limited use of some available improvements that would make force-on-force exercises more realistic and provide a more useful learning experience.

Finally, we also found that even if NRC strengthens its inspection program, commercial nuclear power plants face legal challenges in ensuring plant security. First, federal law generally prohibits guards at these plants from using automatic weapons, although terrorists are likely to have them. As a result, guards at commercial nuclear power plants could be at a disadvantage in firepower, if attacked. Second, state laws regarding the permissible use of deadly force and the authority to arrest and detain intruders vary, and guards were unsure about the extent of their authorities and may hesitate or fail to act if the plant is attacked. GAO made recommendations to promptly restore annual security inspections and revise force-on-force exercises. NRC disagreed with many of GAO's findings, but did not comment on GAO's recommendations.

In September 2004, we testified on our preliminary observations regarding NRC's efforts to improve security at nuclear power plants.[4] The events of September 11, 2001, and the subsequent discovery of commercial nuclear power plants on a list of possible terrorist targets have focused considerable attention on plants' capabilities to defend against a terrorist attack. NRC is responsible for regulating and overseeing security at commercial nuclear power plants. We were asked to review (1) NRC's efforts since September 11, 2001, to improve security at nuclear power plants, including actions NRC had taken to implement some of GAO's September 2003 recommendations to improve security oversight, and (2) the extent to which NRC is in a position to assure itself and the public that the plants are protected against terrorist attacks. The testimony reflected the preliminary results of GAO's review. We are currently performing a more comprehensive review in which we are examining (1) NRC's development of its 2003 design basis threat (DBT), which establishes the maximum terrorist threat that commercial nuclear power plants must defend against, and (2) the security enhancements that plants have put in place in response to the design basis threat and related NRC requirements. We expect to issue a report on our findings later this year.

In the earlier work, we found that NRC responded quickly and decisively to the September 11, 2001, terrorist attacks with multiple steps to enhance security at commercial nuclear power plants. NRC immediately advised plants to go to the highest level of security using the system in place at the time, and issued advisories and orders for plants to make certain enhancements, such as installing more physical barriers and augmenting security forces, which could be quickly completed to shore up security. According to NRC officials, their inspections found that plants complied with these advisories and orders. Later, in April 2003, NRC issued a new DBT and required the plants to develop and implement new security plans to address the new threat by October 2004. NRC is also improving its force-on-force exercises, as GAO recommended in its September 2003 report. While its efforts had enhanced security, NRC was not yet in a position to provide an independent determination that each plant has taken reasonable and appropriate steps to protect against the new DBT. According to NRC officials, the facilities' new security plans were on schedule to be implemented by October 2004. However, NRC's review of the plans, which are not available to the general public for security

[4]GAO, *Nuclear Regulatory Commission: Preliminary Observations on Efforts to Improve Security at Nuclear Power Plants*, GAO-04-1064T (Washington, D.C.: Sept. 14, 2004).

reasons, had primarily been a paper review and was not detailed enough for NRC to determine if the plans would protect the facility against the threat presented in the DBT. In addition, NRC officials generally were not visiting the facilities to obtain site-specific information and assess the plans in terms of each facility's design. NRC is largely relying on the force-on-force exercises it conducts to test the plans, but these exercises will not be conducted at all facilities for 3 years. We also found that NRC did not plan to make some improvements in its inspection program that GAO previously recommended. For example, NRC was not following up to verify that all violations of security requirements had been corrected, nor was the agency taking steps to make "lessons learned" from inspections available to other NRC regional offices and nuclear power plants.

Operations Related to NRC's Public Health and Safety and Environmental Missions Can Be Improved

In October 2003, we reported that NRC needs to more effectively analyze whether nuclear power plant owners are adequately accumulating funds for decommissioning plants.[5] Following the closure of a nuclear power plant, a significant radioactive waste hazard remains until the waste is removed and the plant site is decommissioned. In 1988, NRC began requiring owners to (1) certify that sufficient financial resources would be available when needed to decommission their nuclear power plants and (2) require them to make specific financial provisions for decommissioning. In 1999, GAO reported that the combined value of the owners' decommissioning funds was insufficient to ensure enough funds would be available for decommissioning. GAO was asked to update its 1999 report, and to evaluate NRC's analysis of the owners' funds and the agency's process for acting on reports that show insufficient funds.

We found that although the collective status of the owners' decommissioning fund accounts has improved considerably since GAO's last report, some individual owners were not on track to accumulate sufficient funds for decommissioning. Based on our analysis and using the most likely economic assumptions, we concluded that the combined value of nuclear power plant owners' decommissioning fund accounts in 2000—about $26.9 billion—was about 47 percent greater than needed at that point to ensure that sufficient funds would be available to cover the approximately $33 billion in estimated decommissioning costs when the

[5]GAO: *Nuclear Regulation: NRC Needs More Effective Analysis to Ensure Accumulation of Funds to Decommission Nuclear Power Plants*, GAO-04-32 (Washington, D.C.: Oct. 30, 2003).

plants are permanently closed. This value contrasts with GAO's prior finding that 1997 account balances were collectively 3 percent below what was needed. However, overall industry results can be misleading. Because funds are generally not transferable from funds that have more than sufficient reserves to those with insufficient reserves, each individual owner must ensure that enough funds are available for decommissioning their particular plants. We found that 33 owners with ownership interests in a total of 42 plants had accumulated fewer funds than needed through 2000, to be on track to pay for eventual decommissioning. In addition, 20 owners with ownership interests in a total of 31 plants recently contributed less to their trust funds than we estimated they needed in order to put them on track to meet their decommissioning obligations.

NRC's analysis of the owners' 2001 biennial reports was not effective in identifying owners that might not be accumulating sufficient funds to cover their eventual decommissioning costs. In reviewing the 2001 reports, NRC reported that all owners appeared to be on track to have sufficient funds for decommissioning. In reaching this conclusion, NRC relied on the owners' future plans for fully funding their decommissioning obligations. However, based on the owners' actual recent contributions, and using a different method, GAO found that several owners could be at risk of not meeting their financial obligations for decommissioning when these plants stop operating. In addition, for plants with more than one owner, NRC did not separately assess the status of each co-owner's trust funds against each co-owner's contractual obligation to fund decommissioning. Instead, NRC assessed whether the combined value of the trust funds for the plant as a whole were reasonable. Such an assessment for determining whether owners are accumulating sufficient funds can produce misleading results because owners with more than sufficient funds can appear to balance out owners with less than sufficient funds, even though funds are generally not transferable among owners. Furthermore, we found that NRC had not established criteria for taking action when it determines that an owner is not accumulating sufficient decommissioning funds.

We recommended that NRC (1) develop an effective method for determining whether owners are accumulating decommissioning funds at sufficient rates and (2) establish criteria for taking action when it is determined that an owner is not accumulating sufficient funds. NRC disagreed with these recommendations, suggesting that its method is effective and that it is better to deal with unacceptable levels of financial assurance on a case-by-case basis. GAO continues to believe that limitations in NRC's method reduce its effectiveness and that, without criteria, NRC might not be able to ensure owners are accumulating decommissioning funds at sufficient rates.

In May 2004, we issued a report on NRC's liability insurance requirements for nuclear power plants owned by limited liability companies.[6] An accident at one the nation's commercial nuclear power plants could result in personal injury and property damage. To ensure that funds would be available to settle liability claims in such cases, the Price-Anderson Act requires licensees of 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 of nuclear power plants 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—which shield their parent corporations' assets—will have the financial resources to pay their retrospective premiums. We were asked 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.

We found that of the 103 operating nuclear power plants, 31 were owned by 11 limited liability companies. Three energy corporations—Exelon, Entergy, and the Constellation Energy Group—were the parent companies for eight of these limited liability companies. These 8 subsidiaries were the licensees or co-licensees for 27 of the 31 plants. We also found that 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 sign an agreement with NRC that requires the licensee to keep the insurance in effect. American Nuclear Insurers also has a contractual agreement with each of the licensees that obligates the licensee to pay the retrospective premiums to American Nuclear Insurers if these payments become necessary. A certified copy of this agreement, which is called a bond for payment of retrospective premiums,

[6] GAO, *Nuclear Regulation: NRC's Liability Insurance Requirements for Nuclear Power Plants Owned by Limited Liability Companies*, GAO-04-654 (Washington, D.C.: May 28, 2004).

is provided to NRC as proof of secondary insurance. Finally, we found that 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 that it has received these letters.

In May 2004, we also issued a report documenting the need for NRC to more aggressively and comprehensively resolve issues related to the shutdown of the Davis-Besse nuclear power plant.[7] The most serious safety issue confronting the nation's commercial nuclear power industry since Three Mile Island in 1979, was identified at the Davis-Besse plant in Ohio in March of 2002. After NRC allowed Davis-Besse to delay shutting down to inspect its reactor vessel for cracked tubing, the plant found that leakage from these tubes had caused extensive corrosion on the vessel head—a vital barrier in preventing a radioactive release. GAO determined (1) why NRC did not identify and prevent the corrosion, (2) whether the process NRC used in deciding to delay the shutdown was credible, and (3) whether NRC is taking sufficient action in the wake of the incident to prevent similar problems from developing at other plants.

We found that NRC should have, but did not identify or prevent the corrosion at Davis- Besse because agency oversight did not produce accurate information on plant conditions. NRC inspectors were aware of indications of leaking tubes and corrosion; however, the inspectors did not recognize the importance of the indications and did not fully communicate information about them to other NRC staff. NRC also considered FirstEnergy—Davis-Besse's owner—a good performer, which resulted in fewer NRC inspections and questions about plant conditions. NRC was aware of the potential for cracked tubes and corrosion at plants like Davis-Besse but did not view them as an immediate concern. Thus, despite being aware of the development of potential problems, NRC did not modify its

[7] GAO, *Nuclear Regulation: NRC Needs to More Aggressively and Comprehensively Resolve Issues Related to the Davis-Besse Nuclear Power Plant's Shutdown*, GAO-04-415 (Washington, D.C.: May 17,2004).

inspection activities to identify such conditions. Additionally, NRC's process for deciding to allow Davis-Besse to delay its shutdown lacked credibility. Because NRC had no guidance for making the specific decision of whether a plant should shut down, it instead used guidance for deciding whether a plant should be allowed to modify its operating license. However, NRC did not always follow this guidance and generally did not document how it applied the guidance. Furthermore, the risk estimate NRC used to help decide whether the plant should shut down was also flawed and underestimated the risk that Davis-Besse posed. Finally, even though it underestimated the risk posed by Davis-Besse, the risk estimate applied to the plant still exceeded levels generally accepted by the agency. Nevertheless, Davis-Besse was allowed to delay the plant's shutdown.

After this incident, NRC took several significant actions to help prevent reactor vessel corrosion from recurring at nuclear power plants. For example, NRC has required more extensive vessel examinations and augmented inspector training. I would also like to note that, in April 2005, NRC proposed a $5.45 million fine against the licensee of the Davis-Besse plant. The principal violation was that the utility restarted and operated the plant in May 2000, without fully characterizing and eliminating leakage from the reactor vessel head. Additional violations included providing incomplete and inaccurate information to NRC on the extent of cleaning and inspecting the reactor vessel head in 2000.

While NRC has not yet completed all of its planned actions, we remain concerned that NRC has no plans to address three systemic weaknesses underscored by the incident at Davis-Besse. Specifically, NRC has proposed no actions to help it better (1) identify early indications of deteriorating safety conditions at plants, (2) decide whether to shut down a plant, or (3) monitor actions taken in response to incidents at plants. Both NRC and GAO had previously identified problems in NRC programs that contributed to the Davis-Besse incident, yet these problems continued to persist. Because the nation's nuclear power plants are aging, GAO recommended that NRC take more aggressive actions to mitigate the risk of serious safety problems occurring at Davis-Besse and other nuclear power plants.

In April 2005, we issued a report outlining the need for NRC to do more to ensure that power plants are effectively controlling spent nuclear fuel.[8] Spent nuclear fuel—the used fuel periodically removed from reactors in nuclear power plants—is too inefficient to power a nuclear reaction, but is intensely radioactive and continues to generate heat for thousands of years. Potential health and safety implications make the control of spent nuclear fuel of great importance. The discovery, in 2004, that spent fuel rods were missing at the Vermont Yankee plant in Vermont generated public concern and questions about NRC's regulation and oversight of this material. GAO reviewed (1) plants' performance in controlling and accounting for their spent nuclear fuel, (2) the effectiveness of NRC's regulations and oversight of plants' performance, and (3) NRC's actions to respond to plants' problems controlling their spent fuel.

We found that nuclear power plants' performance in controlling and accounting for their spent fuel has been uneven. Most recently, three plants—Vermont Yankee and Humboldt Bay (California) in 2004, and Millstone (Connecticut) in 2000—have reported missing spent fuel. Earlier, several other plants also had missing or unaccounted for spent fuel rods or rod fragments. NRC regulations require plants to maintain accurate records of their spent nuclear fuel and to conduct a physical inventory of the material at least once a year. The regulations, however, do not specify how physical inventories are to be conducted. As a result, plants differ in the regulations' implementation. For example, physical inventories at plants varied from a comprehensive verification of the spent fuel to an office review of the records and paperwork for consistency. Additionally, NRC regulations do not specify how individual fuel rods or segments are to be tracked. As a result, plants employ various methods for storing and accounting for this material. Further, NRC stopped inspecting plants' material control and accounting programs in 1988. According to NRC officials, there was no indication that inspections of these programs were needed until the event at Millstone. At the time of our review, NRC was collecting information on plants' spent fuel programs to decide if it needs to revise its regulations and/or oversight. It had its inspectors collect basic information on all facilities' programs. It also contracted with the Department of Energy's Oak Ridge National Laboratory in Tennessee to review NRC's material control and accounting programs for nuclear

[8]GAO, *Nuclear Regulatory Commission: NRC Needs to Do More to Ensure that Power Plants Are Effectively Controlling Spent Nuclear Fuel*, GAO-05-339 (Washington, D.C.: Apr. 8, 2005).

material. NRC is planning to request information from plants and plans to visit over a dozen plants for more detailed inspection. The results of these efforts may not be completed until late 2005, over 5 years after the incident at Millstone that initiated NRC's efforts. However, we believed NRC has already collected considerable information indicating problems or weaknesses in plants' material control and accounting programs for spent fuel.

GAO recommended that NRC (1) establish specific requirements for the way plants control and account for loose rods and fragments as well as conduct their physical inventories, and (2) develop and implement appropriate inspection procedures to verify plants' compliance with the requirements.

NRC Faces Several Broad Challenges in Effectively Regulating and Overseeing Nuclear Power Plants

Based on our recent work at NRC, we have identified several cross-cutting challenges that NRC faces as it works to effectively regulate and oversee the nuclear power industry. First, NRC must manage the implementation of its risk-informed regulatory strategy across the agency's operations. Second, and relatedly, NRC must strive to achieve the appropriate balance between more direct involvement in the operations of nuclear power plants and self-reliance and self-reporting on the part of plant operators to do the right things to ensure safety. Third, and finally, NRC must ensure that the agency effectively manages resources to implement its risk-informed strategy and achieve the appropriate regulatory balance in the current context of increasing regulatory and oversight demands as the industry's interest in expansion grows.

NRC Must Manage the Implementation of Its Risk-Informed Regulatory Strategy

Nuclear power plants have many physical structures, systems, and components, and licensees have numerous activities under way, 24-hours a day, to ensure that plants operate safely. NRC relies on, among other things, the agency's on-site resident inspectors to assess plant conditions and oversee quality assurance programs, such as maintenance and operations, established by operators to ensure safety at the plants. Monitoring, maintenance, and inspection programs are used to ensure quality assurance and safe operations. To carry out these programs, licensees typically prepare numerous reports describing conditions at plants that need to be addressed to ensure continued safe operations. Because of the significant number of activities and physical structures, systems, and components, NRC adopted a risk-informed strategy to focus inspections on those activities and pieces of equipment that are considered to be the most significant for protecting public health and safety. Under the risk-informed approach, some systems and activities that NRC considers to have relatively less safety significance receive little agency oversight. With its current resources, NRC can inspect only a relatively small sample of the numerous activities going on during complex plant operations. NRC has adopted a risk-informed approach because it believes that it can focus its regulatory resources on those areas of the plant that the agency considers the most important to safety. NRC has stated the adoption of this approach was made possible by the fact that safety performance at plants has improved as a result of more than 25 years of operating experience.

Nevertheless, we believe that NRC faces a significant challenge in effectively implementing its risk-informed strategy, especially with regards to improving the quality of its risk information and identifying emerging technical issues and adjusting regulatory requirements before safety problems develop. The 2002 shutdown of the Davis-Besse plant illustrates this challenge, notably the shortcomings in NRC's risk estimate and failure to sufficiently address the boric acid corrosion and nozzle cracking issues. We also note that NRC's Inspector General considers the development and implementation of a risk-informed regulatory oversight strategy to be one of the most serious management challenges facing NRC.

NRC Must Balance Oversight and Industry Self-Compliance

Under the Atomic Energy Act of 1954, as amended, and the Energy Reorganization Act of 1974, as amended, NRC and the operators of nuclear power plants share the responsibility for ensuring that nuclear reactors are operated safely. NRC is responsible for issuing regulations, licensing and inspecting plants, and requiring action, as necessary, to protect public health and safety. Plant operators have the primary responsibility for safely operating their plants in accordance with their licenses. NRC has the authority to take actions, up to and including shutting down a plant, if licensing conditions are not being met and the plant poses an undue risk to public health and safety.

NRC has sought to strike a balance between verifying plants' compliance with requirements through inspections and affording licensees the opportunity to demonstrate that they are operating their plants safely. While NRC oversees processes, such as the use of performance measures and indicators, and requirements that licensees maintain their own quality assurance programs, NRC, in effect, relies on licensees and trusts them to a large extent to make sure their plants are operated safely. While this approach has generally worked, we believe that NRC still has work to do to effectively position itself so that it can identify problems with diminishing performance at individual plants before they become serious. For example, incidents such as the 2002 discovery of the extensive reactor vessel head corrosion at the Davis-Besse plant and the unaccounted for spent nuclear fuel at several plants across the country, raise questions about whether NRC is appropriately balancing agency involvement and self-monitoring by licensees. An important aspect of NRC's ability to rely on licensees to maintain their own quality assurance programs is a mechanism to identify deteriorating performance at a plant before the plant becomes a problem. At Davis-Besse, NRC inspectors viewed the licensee as a good performer based on its past performance and did not ask the questions that should have been asked about plant conditions. Consequently, the inspectors did not make sure that the licensee adequately investigated the indications of the problem and did not fully communicate the indications to the regional office and NRC headquarters.

NRC Must Manage Agency Resources to Meet Increasing Regulatory and Oversight Demands

Finally, Mr. Chairman, I would also like to comment briefly on NRC's resources. While we have not assessed the adequacy of NRC's resources, we have noted instances, such the shutdown of the Davis-Besse plant, where resource constraints affected the agency's oversight or delayed certain activities. NRC's resources have been challenged by the need to enhance security at nuclear power plants after the September 11, 2001, terrorist attacks, and they will continue to be challenged as the nation's fleet of nuclear power plants age and the industry's interest grows in both licensing and constructing new plants, and re-licensing and increasing the output of existing plants. Resource demands will also increase when the Department of Energy submits for NRC review, an application to construct and operate a national depository for high-level radioactive waste currently planned for Yucca Mountain, Nevada. We believe that it is important for NRC and the Congress to monitor agency resources as these demands arise in order to ensure that NRC can meet all of its regulatory and oversight responsibilities and fulfill its mission to ensure adequate protection of public health, safety, and the environment.

Conclusion

In closing, we recognize and appreciate the complexities of NRC's regulatory and oversight efforts required to ensure the safe and secure operation of the nation's commercial nuclear power plants. As GAO's recent work has demonstrated, NRC does a lot right but it still has important work to do. Whether NRC carries out its regulatory and oversight responsibilities in an effective and credible manner will have a significant impact on the future direction of our nation's use of nuclear power.

Finally, we note that NRC has generally been responsive to our report findings. Although the agency does not always agree with our specific recommendations, it has continued to work to improve in the areas we have identified. It has implemented many of our recommendations and is working on others. For example, with respect to nuclear power plant security, NRC has restored its security inspection program and resumed its force-on-force exercises with a much higher level of intensity. It is also strengthening these exercises by conducting them at individual plants every 3 years rather than every 8 years, and is using laser equipment to reduce the exercises' artificiality. Another example involves sealed radioactive sources. NRC is working with agreement states to develop a process for ensuring that high-risk radioactive sources cannot be obtained before verification that the materials will be used as intended. NRC anticipates that an NRC-agreement state working group will deliver a recommended approach to NRC senior management later this year. In addition, NRC continues to work on its broader challenges. For example, the agency intends to develop additional regulatory guidance to expand the application of risk-informed decision making, including addressing the need to establish quality requirements for risk information and specific instructions for documenting the decision making process and its conclusions.

We will continue to track NRC's progress in implementing our recommendations. In addition, as members of this subcommittee are aware, GAO has been asked to review the effectiveness of NRC's activities for overseeing nuclear power plants, that is, its reactor oversight process. An important part of that work would be to review the agency's risk-informed regulatory strategy and its effectiveness in identifying deteriorating plant performance as well as whether NRC is making progress toward effectively balancing agency inspections and self-monitoring by licensees.

Mr. Chairman, this completes my prepared statement. I would be pleased to respond to any questions that you or other Members of the subcommittee may have.

GAO Contacts and Staff Acknowledgements

For further information about this testimony, please contact me at (202) 512-3841 (or at wellsj@gao.gov). John W. Delicath, Ilene Pollack, and Raymond H. Smith, Jr. made key contributions to this testimony.

Related GAO Products

Nuclear Waste: Preliminary Observations on the Quality Assurance Program at the Yucca Mountain Repository. GAO-03-826T. Washington, D.C.: May 28, 2003.

Nuclear Regulatory Commission: Revision of Fee Schedules; Fee Recovery for FY 2003. GAO-03-934R. Washington, D.C.: June 30, 2003.

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Reference 5

EXHIBIT E

Reference "5"
Exhibit "E"

AUDIT REPORT

Audit of NRC's License Renewal Program

OIG-07-A-15 September 6, 2007

All publicly available OIG reports (including this report) are accessible through NRC's Web site at:
http:/www.nrc.gov/reading-rm/doc-collections/insp-gen/

September 6, 2007

MEMORANDUM TO: Luis A. Reyes
Executive Director for Operations

FROM: Stephen D. Dingbaum **/RA/**
Assistant Inspector General for Audits

SUBJECT: AUDIT OF NRC'S LICENSE RENEWAL PROGRAM (OIG-07-A-15)

This report presents the results of the subject audit. The formal comments provided by your office on July 6, 2007, are presented in their entirety as Appendix E to this report. Appendix F contains OIG's response.

Please provide information on actions taken or planned on each of the recommendations within 30 days of the date of this memorandum. Actions taken or planned are subject to OIG follow-up as stated in Management Directive 6.1.

If you have any questions or wish to discuss other issues, please call Tony Lipuma at 415-5910 or me at 415-5915.

Attachment: As stated

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I. EXECUTIVE SUMMARY

BACKGROUND

U.S. Nuclear Regulatory Commission (NRC) regulations limit the term of an initial nuclear reactor operating license to 40 years. However, the regulations also allow a license to be renewed for an additional 20 years given that the initial term was based on economic and anti-trust considerations, not technical limitations. Through technical research, NRC concluded that many aging phenomena are readily managed and therefore should not preclude renewal of a reactor license.

NRC published requirements for license renewal in the *Code of Federal Regulations* (CFR). 10 CFR Part 54[1] addresses operating safety issues — the main focus of this Office of the Inspector General (OIG) report. Part 54 was amended in 1995 to concentrate NRC's reviews on how licensees manage adverse effects of aging to provide reasonable assurance that plants will continue to operate in accordance with their current licensing basis for the period of extended operations.

PURPOSE

The purpose of OIG's audit was to determine the effectiveness of NRC's license renewal safety reviews.

RESULTS IN BRIEF

Overall, NRC has developed a comprehensive license renewal process to evaluate applications for extended periods of operation. However, OIG identified areas where improvements would enhance program operations. Specifically,

[1] 10 CFR Part 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants.*

- License renewal reporting efforts need improvements

    - Reporting issues exist because the agency has not fully established report-writing standards or a report quality assurance process. As a result, those who read the reports could conclude that regulatory decisions are not adequately reviewed and documented.

- Guidance for removing licensee documents from audit sites could be clarified

    - Inconsistencies regarding removal of documents result from audit teams being prohibited by their management from removing licensee-supplied documents from audit sites, whereas the inspectors do keep such documents to assist in report writing. As a result, it is more difficult for audit team members to write their reports without using workaround tools.

- Consistent evaluation of operating experience would improve NRC reviews

    - Although expected to, audit team members do not consistently review or independently verify licensee-supplied operating experience information because program managers have not established requirements and controls to standardize the conduct and depth of such reviews. Consequently, license renewal auditors may not have adequate assurances that relevant operating experience was captured in the licensee's renewal application for NRC's consideration.

- More attention is needed to planning for post-renewal inspections

    - Post-renewal inspections are considered vital to ensure that licensees adhered to commitments made for license renewal. However, the agency has only recently focused its attention on developing and overseeing details associated with these inspections. Inadequate planning increases the risk that: licensees could enter into the extended period of operation without being in full compliance with license renewal terms; inspections will be inconsistently implemented; and inspection and technical support resources will be unavailable when needed.

- License renewal issues need evaluation for backfit application

    - When NRC imposes new staff positions resulting in new review standards, a documented justification is required pursuant to the backfit rule. However, new license renewal review standards have not followed NRC's backfit policy because NRC does not have a mechanism or methodology to trigger such a backfit review. Consequently, the use of different review standards without a backfit justification may result in several management challenges.

RECOMMENDATIONS

This report makes eight recommendations to help NRC improve the effectiveness of its License Renewal Program. Seven of the recommendations are addressed to the Executive Director for Operations. In consideration of the agency's formal comments concerning the applicability of the backfit rule to license renewal applicants, the last recommendation is directed to the Commission. A Consolidated List of Recommendations appears in Section IV.

OIG ANALYSIS OF AGENCY COMMENTS

On May 8, 2007, OIG issued its draft report to the Executive Director for Operations. On July 6, 2007, the Deputy Executive Director for Reactor Programs provided a formal response to this report in which the agency disagreed with OIG's finding regarding applicability of the backfit rule to license renewal applicants. The agency's transmittal letter and specific comments on this report are included in their entirety as Appendix E.

This final report incorporates revisions made, where appropriate, as a result of the subsequent meetings with staff and the agency's written comments. Appendix F contains OIG's analysis of the agency's formal response.

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ABBREVIATIONS AND ACRONYMS

ACRS	Advisory Committee on Reactor Safeguards
ADAMS	Agencywide Documents Access and Management System
CFR	*Code of Federal Regulations*
DLR	Division of License Renewal
FY	fiscal year
GALL	*Generic Aging Lessons Learned*
ISG	Interim Staff Guidance
LRA	license renewal application
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
OGC	Office of the General Counsel
OIG	Office of the Inspector General
SOC	Statement of Considerations
SSC	systems, structures, and components

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I. BACKGROUND

The Atomic Energy Act of 1954, as amended, and U.S. Nuclear Regulatory Commission (NRC) regulations limit the term of an initial nuclear reactor operating license to 40 years. The regulations also allow a license to be renewed for an additional 20 years given that the initial term was based on economic and anti-trust considerations, not technical limitations. Nonetheless, NRC recognizes that some plant systems, structures, and components (SSC) may have been engineered with the expectation of a limited 40-year service life. Through technical research, NRC concluded that many aging phenomena are readily managed and therefore should not preclude renewal of a reactor license.

In the early 1990s, NRC published requirements for license renewal in the *Code of Federal Regulations* (CFR). 10 CFR Part 51 addresses environmental issues.[2] 10 CFR Part 54[3] addresses operating safety issues — the main focus of this Office of the Inspector General (OIG) report. Part 54 was amended in 1995 to concentrate NRC's reviews on <u>how</u> licensees manage adverse effects of aging to provide reasonable assurance that plants will continue to operate in accordance with their current licensing basis for the period of extended operations.

In July 2001, NRC issued NUREG-1801, *Generic Aging Lessons Learned (GALL) Report*, as the agency's primary technical basis document for NRC-approved programs for managing the aging of a large number of structures and components that are subject to aging management reviews.

Agency Assumptions

The two key principles of license renewal are: 1) NRC's existing regulatory process adequately ensures that currently operating plants will continue to maintain adequate levels of safety during extended operation, with the possible exception of detrimental

[2] In response to the National Environmental Policy Act, NRC also pursued an environmental rule, 10 CFR Part 51, *Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions*, revised 1996.

[3] 10 CFR Part 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants.*

effects of aging on certain SSCs, and a few other issues that may arise during the period of extended operation; and 2) each plant's licensing basis is required to be maintained during the renewal term in the same manner and extent as during the original licensing term. NRC incorporates the following assumptions into its reviews of license renewal applications:

- an applicant should rely on the plant's current licensing basis,[4] actual plant-specific experience, applicable industry-wide operating experience, and existing engineering evaluations to determine which plant SSCs are the initial focus of a license renewal review; and

- a plant's "active" components[5] do not require additional review during license renewal because aging effects of active components are more readily detected and corrected through routine surveillance and maintenance. Therefore, the license renewal process limits its reviews to "passive and long-lived" plant structures and components,[6] time-limited aging analyses,[7] and aging management programs for renewal-related components.

Review Process and Program Responsibilities

In order to assess the reliability of its assumptions about aging, NRC uses a review process that proceeds along two parallel tracks:

---

[4] "Current licensing basis" is the set of NRC requirements applicable to a specific plant and a licensee's written regulatory commitments for ensuring compliance and operation within applicable NRC requirements and the plant-specific design basis that are docketed and in effect.

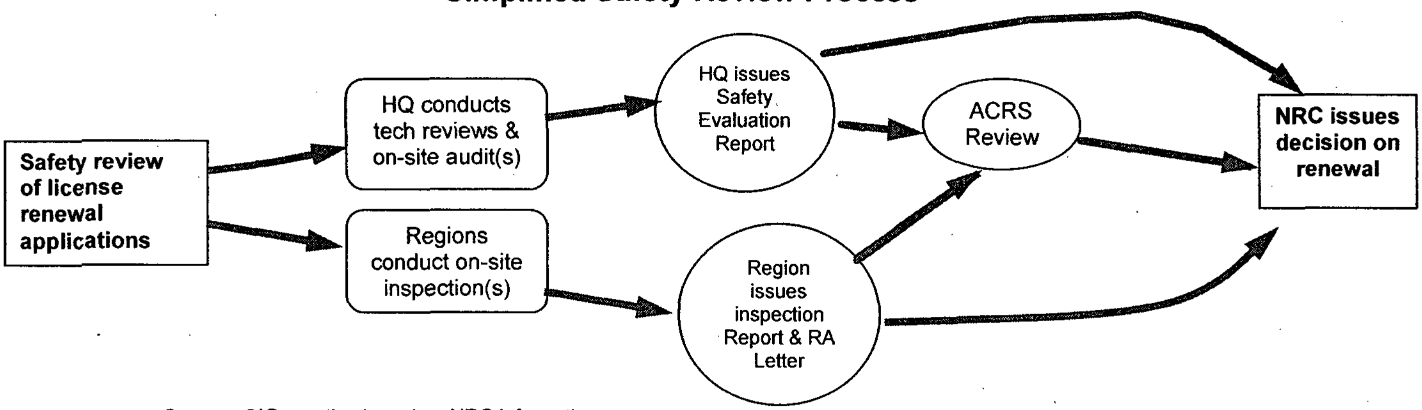
[5] "Active" components include motors, diesel generators, cooling fans, batteries, relays, and switches.

[6] "Passive" and "long-lived" structures and components are those that perform an intended function without moving parts or a change in properties, and those not subject to replacement based on qualified life or specified time period, respectively. Passive and long-lived SSCs include reactor vessels, reactor coolant system piping, steam generators, pressurizers, pump casings, and valve bodies.

[7] "Time-limited aging analyses" are licensee calculations and analyses that: involve SSCs within the scope of license renewal; consider aging effects; involve assumptions defined by the current 40-year operating term; are relevant for making a safety decision; involve basis for decision that SSCs are capable of performing their intended functions; and are contained in or referenced in the current license basis.

a safety review (Part 54) and an environmental review (Part 51). Figure 1 reflects a simplified license renewal <u>safety</u> review process. (See Appendix B for the NRC's dual-track license renewal review process.)

Figure 1
Simplified Safety Review Process



Source: OIG-creation based on NRC information

As reflected in Figure 1, the safety review process consists of headquarters-based technical reviews, on-site audits, and region-based inspections. Primary responsibility for the license renewal program lies within NRC's Office of Nuclear Reactor Regulation (NRR), Division of License Renewal (DLR). DLR project teams, consisting of technical auditors and engineer consultants, perform on-site audits to review the supporting documentation for those aging management programs and aging management reviews cited in the licensee's application as consistent with the *GALL Report* or based on NRC-accepted past precedence. Concurrently, NRR's headquarters-based engineering divisions review scoping and screening of SSCs, plant-specific aging management programs and aging management reviews, and other items not addressed in the *GALL Report* (e.g., unresolved or emergent issues). The results of the NRC staff's review are documented in a safety evaluation report.

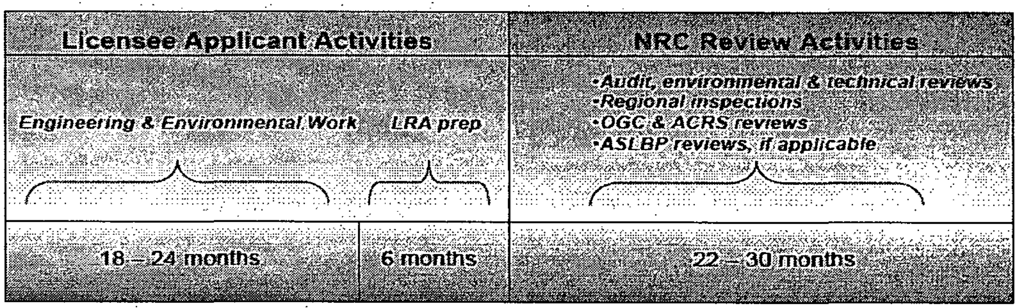
Additionally, teams of specialized inspectors from NRC's four region offices travel to the reactor sites to verify the licensees' claims that current or proposed aging management programs will be effective.

The Advisory Committee on Reactor Safeguards (ACRS) acts as an independent third-party oversight group who reviews safety evaluation report findings as well as inspection report findings and makes recommendations on the renewal application to the Commission. Throughout the process, NRC's Office of the General Counsel (OGC) provides legal and regulatory interpretations as needed and formally reviews and concurs on the safety evaluation reports. When applicable, the Atomic Safety and Licensing Board rules on stakeholders' requests for license renewal hearings.

Application Review Timelines and Costs [8]

As shown in Figure 2, renewal application processing can take more than 4 years – approximately 2 years and $20 million is spent by licensees to research, document, and prepare a license renewal application for submission. For NRC's review and decision on an application, it typically takes 22 months and $4 million without a hearing, and a projected 30 months[9] with a hearing.

Figure 2
Application Preparation and Review Process



[8] Regulations allow for renewal applications to be submitted as early as 20 years before expiration of a current license, but licensees technically have until the end of their 40-year license to apply for an extension. However, NRC notes that if a "sufficient" application is not submitted at least 5 years prior to license expiration, a plant may have to cease operations until the renewal decision is made.

[9] OIG notes that NRC's projected 30-month schedule, including a hearing, has not yet been tested because none of the license renewals granted to date went through a hearing process.

Status of License Renewals

The agency's extensive experience with license renewal issues began in 1982. As of April 2007, approximately one-half of the Nation's licensed reactors have either received renewed licenses or are currently under review. Specifically, license extension requests for 48 of the 104 licensed power reactor units in the U.S. have been reviewed and approved. Additionally, eight renewal applications are currently under review while licensees representing an additional 23 plants have announced intentions to submit renewal applications through 2013.

Proactive License Renewal Program Features

NRC incorporated several features into the license renewal program that correspond to the agency's Principles of Good Regulation. For example,

- Several facets of <u>openness</u> are built into the process for public involvement, including open meetings and opportunities to request an adjudicatory hearing.

- For a more <u>efficient</u> license renewal review process:

    - the *GALL Report* was developed to document the basis for determining whether existing programs are adequate and for identifying those programs that warrant particular attention during NRC's review of a license renewal application,

    - NRC Regulatory Guide 1.188[10] helps standardize the format and content of license renewal applications, and

    - the audit function enables NRC staff to review more applications simultaneously by reducing the need for requests for additional information.

[10] Regulatory Guide 1.188, *Standard Format and Content For Applications to Renew Nuclear Power Plant Operating Licenses.*

- Some NRC staff and industry representatives made favorable comments to OIG about the clarity of NRC's guidance regarding the expected content for a renewal application and NRC's adherence to its established review schedule, which provides reliable planning assistance to NRC technical engineering divisions and future license renewal applicants.

II. PURPOSE

The purpose of OIG's audit was to determine the effectiveness of NRC's license renewal safety reviews. Appendix A provides a detailed description of the audit's scope and methodology.

III. FINDINGS

Overall, NRC has developed a comprehensive license renewal process to evaluate applications for extended periods of operation. However, OIG identified areas where improvements would enhance program operations. Specifically,

A. license renewal reporting efforts need improvements,

B. guidance for removing licensee documents from audit sites could be clarified,

C. consistent evaluation of operating experience would improve NRC reviews,

D. more attention is needed to planning for post-renewal inspections, and

E. license renewal issues need evaluation for backfit application.

A. NRC's License Renewal Reporting Efforts Need Improvements

Improvements to the staff's reporting efforts could provide necessary support for NRC's license renewal decisions. Adequate documentation of review methodologies and support for staff conclusions in license renewal reports is important for supporting the sufficiency and rigor of NRC's review process. However, the NRC staff does not consistently provide adequate descriptions of audit methodology or support for conclusions in license renewal reports. This is because DLR has not fully established report-writing standards and does not have a report quality assurance process to ensure adequate documentation. As a result, stakeholders and others who read the reports could conclude that regulatory decisions are not adequately reviewed and documented.

Review Documentation Standards and Current Guidance

NRC's license renewal reviews must be supported to demonstrate the adequacy and rigor of NRC's review process. One way to accomplish this is to have documentation to support conclusions in NRC's license renewal reports, which include the license renewal audit, inspection, and safety evaluation reports. DLR's audit guidance also acknowledges the importance of documentation for reaching conclusions in the audit reports.

DLR is responsible for conducting on-site audits of the license renewal applications. The license renewal auditors, referred to internally as the project team, use a handbook titled, *Project Team Guidance for License Renewal Application Safety Reviews,* to guide the conduct of the audit. A peer review checklist in the *Project Team Guidance* reminds the reviewer to make sure the conclusions in the audit report are supported by adequate technical bases.

Review Methodology and Conclusions are Not Fully Described in Reports

License renewal audit, inspection, and safety evaluation reports do not provide full descriptions of the methodology the staff used to review an aging management program or provide full support for the staff's conclusions. In some cases, the language presented in the audit and safety evaluation reports mirrors the language provided by the licensee in its license renewal application, which, according to NRC, may have been taken by the licensee out of the *GALL Report* and placed in the application.

OIG performed a content analysis of audit, inspection, and safety evaluation reports for a judgmental sample[11] of license renewal applications submitted between September 2000 and January 2006.[12] For its analysis, OIG focused on narrative passages in the applications and reports that addressed the operating experience program element for a selection of aging management programs.[13] OIG's analysis resulted in 458 report narrative samples.

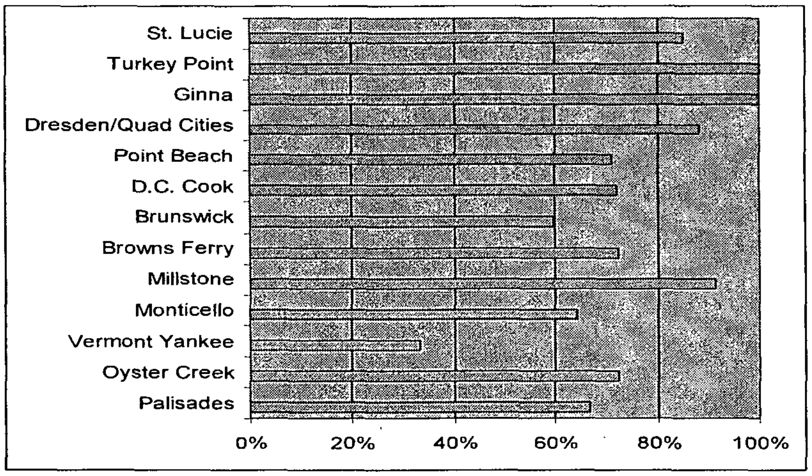
[11] Results of this judgmental sample are limited to the population of license renewal applications sampled.

[12] The judgmental sample of applications represents a cross-section of plant ages, technologies, year of renewal, NRC application review process used, and NRC region. A detailed description of OIG's content analysis methodology is presented in Appendix C.

[13] Operating experience is one of ten GALL program elements that a licensee's aging management program must satisfy in order to secure approval from NRC.

OIG found that approximately 76 percent of the audit, inspection, and safety evaluation report samples did not provide substantive NRC comments about operating experience. Operating experience is a critical facet of the review process. For its analysis, OIG defined non-substantive samples as those that 1) did not describe *any* review methodology for operating experience or provide *any* specific support for the staff's conclusions; or 2) provided information that was identical or nearly identical to the information provided in the licensee's renewal application. Figure 3 depicts, by plant license renewal application, the percent of report samples that did not provide substantive NRC comments about operating experience.

Figure 3
Percent of Report Samples Lacking Substantive Operating Experience Comments, by Plant



Source: OIG analysis of NRC license renewal audit, inspection, and safety evaluation reports; and of license renewal applications.

In some cases, the identical or nearly identical word-for-word repetition of renewal application text found in the audit, inspection, or safety evaluation reports are not offset or otherwise marked to indicate the text is identical to that found in the license renewal application. The lack of precision in differentiating quoted and unquoted text makes it difficult for the reader to distinguish between the licensee-provided data and NRC staff's independent assessment methodology and conclusion. A reader could conclude that they were reading NRC's independent analysis and conclusions when, in fact, it was the licensee's conclusions. While

NRC reviewers may have actually performed such an independent review, a comparison between the license renewal application and the audit report may cast doubt as to what, exactly, NRC did to independently review the licensee's program other than restate what was provided in the renewal application.

For example, NRC's narrative description of operating experience for Millstone's flow-accelerated corrosion program is nearly identical to the description provided in the licensee's renewal application. NRC's Millstone audit report, shown on the right side of Table 1 below, presents information about the trending successes in the Millstone flow-accelerated corrosion program and gives the appearance of the audit team's independent review and analysis. In fact, this passage is nearly identical to that presented in the license renewal application, shown in the left column of the table. Moreover, while NRC states that the project team reviewed operating experience, there is no discussion of what precisely was reviewed.

Table 1
Sample Comparison of Licensee and NRC Report Narrative[14]

Millstone Unit 2 renewal application	NRC's Millstone renewal audit report
The number of planned and unplanned replacements has generally trended downward over the past several years due to the establishment of the Flow-Accelerated Corrosion program and following the recommendations identified in NSAC-202L. (p. B-42)	*The project team reviewed operating experience for the applicant's Flow-Accelerated Corrosion program. The number of planned and unplanned replacements has generally trended downward over the past several years due to the establishment of the Flow-Accelerated Corrosion program and following the recommendations identified in NSAC-202L. (p. 67-8)*

Source: OIG analysis

[14] Additional examples are provided in Appendix D.

NRC staff stated that when the licensee claims an aging management program is consistent with the *GALL Report*, the licensee may copy the operating experience from the *GALL Report,* and the safety evaluation report may copy the application. However, OIG's analysis shows that—for the audit, inspection, and safety evaluation reports sampled—the staff's description of the methods used and the support they provided for their conclusions often lack substance.

Staff Report-Writing Standards Are Not Fully Established

DLR management has not fully established report-writing standards for describing the license renewal review methodology and providing support for conclusions in NRC license renewal audit, inspection, and safety evaluation reports. DLR managers said that they expected license renewal staff to use their own language and avoid copying directly from the license renewal application when writing renewal reports. The managers said they are aware of the importance of demonstrating NRC's independence in the license renewal reviews. DLR managers also said that they have verbally communicated and stressed their expectations to the staff. Yet, the *Project Team Guidance* does not reiterate these expectations or provide any report-writing standards that would support management's expectations. The *Project Team Guidance* instead focuses on the process of compiling the audit and safety evaluation reports and not on the quality of information presented in these reports.

DLR management pointed to some report quality assurance tools that involved audit team leader, peer group, and branch chief reviews of the audit and safety evaluation reports. DLR places the greatest emphasis on the audit team leader review to control report quality. DLR management and staff said that the peer review, conducted near the end of the report-writing process, is not a page-by-page review of the audit and safety evaluation reports but is primarily a spot review seeking to correct major mistakes in the reports. However, these tools have not ensured that the reports contain substantive documentation of NRC's application review methodology and independent support for staff conclusions.

Essentially, DLR lacks a complete report quality assurance process to ensure documentation of the staff's aging management program review methodology and substantive support for staff conclusions.

While the team leader and peer review tools currently in place could form the basis of a report quality assurance process, DLR does not currently have any way to measure or determine the effectiveness of these team leader and peer reviews. Nor does the Division have procedures that would specify additional report quality assurance steps to take, given a pattern or trend in discovered problems. Such procedures would help DLR management refine the report quality assurance process to meet the quality assurance needs of the audit teams and division directors, as well as those—like ACRS members—who depend on the audit and safety evaluation reports for their review responsibilities.

NRC Basis for Conclusions Important to Stakeholders

The basis for conclusions reached by NRC license renewal review staff is important to stakeholders and others who read NRC's reports. The lack of an effective report quality assurance process to ensure that review methodology and support for conclusions are provided in the license renewal reports could lead readers to conclude that regulatory decisions are not adequately reviewed and documented. Furthermore, providing more substantive analysis and conclusions would help NRC better meet its strategic goal of transparency.

NRC internal users—such as members of the ACRS—benefit from more substantive discussions of license renewal review methodologies and support for conclusions. ACRS members said that they rely on information in all of the license renewal reports, and pointed specifically to the value of the level of detail in the audit reports.

RECOMMENDATIONS:

OIG recommends that the Executive Director for Operations:

1. Establish report-writing standards in the *Project Team Guidance* for describing the license renewal review methodology and providing support for conclusions in the license renewal reports.

2. Revise the report quality assurance process for license renewal report review to include:

   - establishing management controls for NRR and DLR management to gauge the effectiveness of team leader and peer group report reviews, and

   - implementing procedures that would specify additional report quality assurance steps to be taken in the event that the team leader and peer group report reviews fail to ensure report quality to management's expectations.

B. Guidance for Removing Licensee Documents from Audit Sites Could Be Clarified

OIG found inconsistencies in the guidance provided to license renewal auditors with regard to removing licensee documents obtained at audit sites. License renewal audit teams should collect and document the information they review during site visits. However, audit teams are prohibited by DLR from removing licensee documents from the audit site, which makes it more difficult for audit team members to write their reports without using workaround tools. DLR's policy also creates document handling inconsistencies with inspectors, who do keep documents obtained from the licensee's site.

Information Collection Guidance

As noted earlier, the license renewal audit team uses the *Project Team Guidance,* to guide the conduct of the audit. With regard to documentation, the *Project Team Guidance* exhorts auditors to "properly collect and document the information they review during site visits," especially for information used as a basis for reaching a conclusion regarding the audit and safety evaluation reports.

Audit Teams Prohibited from Removing Licensee Documents from Audit Site

License renewal audit teams, as a matter of DLR policy, are prohibited by their management from removing copies of licensee-provided documents from the audit site. The licensee provides an extensive amount of bases and technical documents for DLR auditors. DLR auditors review these documents for information that may answer their questions about the license renewal application. Licensee staff may exert great effort to make multiple copies of documents available, both in hard copy and on compact disc. Because DLR management prohibits auditors from removing licensee-provided documents, auditors use the time available on-site to peruse the documents and interview licensee staff.

License renewal auditors said that being allowed to take documents offsite would aid them in writing and supporting their audit and safety evaluation report inputs. They thus resorted to removing documents provided by the licensee in violation of the Division's policy.

DLR management's policy to prohibit license renewal auditors from removing licensee-provided documents from the audit site is also contrary to the policy and practice for license renewal inspectors. For example, NRC region-based license renewal inspectors said that the renewal inspection teams can and do take documents from the site. The inspectors said it is standard procedure to dispose of licensee documents once their report is written.

Guidance for Removing Licensee Documents from Audit Sites is Inconsistent

OIG found inconsistencies in the guidance provided to license renewal auditors with regard to removing copies of licensee-provided documents from audit sites. DLR management provides the audit teams with verbal guidance to never remove licensee documents obtained from the audit site. However, DLR's *Project Team Guidance* appears to permit some removal of licensee documents from an audit site, as indicated on page 26:

> *"The project team shall not take documents from an applicant's site for in-office review, unless the documents are either already in ADAMS or the applicant agrees that the NRC can put the document in ADAMS."*[15]

Elsewhere, the *Project Team Guidance* states that "if the documentation cannot go on the docket or into ADAMS then it cannot be taken off site." A more permissive document removal policy is provided to inspectors through Inspection Manual Chapter 0620.[16] It provides a number of acceptable practices for obtaining licensee documents, including sending an inspector to the site or using the licensee's equipment to make copies of relevant materials. The guidance states that copies of licensee records and documents may be reviewed offsite with the licensee's permission.

When asked the reason for the more restrictive verbal removal policy, DLR managers echoed the rationale provided by the *Project Team Guidance*. They said that most documents provided by the

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[15] ADAMS is NRC's Agencywide Documents Access and Management System.

[16] Inspection Manual Chapter 0620, *Inspection Documents and Records*, dated January 27, 2006.

licensee at the audit site have not been docketed by NRC and, therefore, DLR does not want license renewal auditors to bring the undocketed items back to headquarters. According to DLR management, OGC told NRR staff that all documents that NRC auditors bring back "must be docketed."

A senior attorney involved with the License Renewal Program said that OGC warned NRR management not to take documents unless they are willing to "give them up" through a Freedom of Information Act request or via a mandatory disclosure requirement for a hearing. The OGC attorney could not identify any specific guidance that required NRC to put licensee documents on the docket, and admitted that NRC's criteria regarding what licensee documents must be docketed by the agency is unclear.

The OGC attorney also said that the practice among region-based inspectors to remove licensee-provided documents from a license renewal site is acceptable. However, the attorney expressed concern about the inconsistent practices of the license renewal audit and inspection staffs regarding the removal of documents from license renewal sites.

Consequences of DLR's Documentation Policies and Practices

DLR's prohibition on its audit staff from removing documents provided by the licensee at license renewal sites makes it more difficult for the auditors to write their inputs to the audit and safety evaluation reports. Instead, the audit staff has to rely on notes and memory, and use other source document workarounds—such as worksheets and the licensee-managed database of questions and answers—to construct input for the audit and safety evaluation reports. Given the Division's greater reliance on the staff to perform audits with fewer contractors, any effort to provide auditors with source documents may contribute to review efficiencies.

Furthermore, NRR's policy also leads to document handling inconsistencies between the license renewal audit and inspection teams. The same blanket prohibition on removal of licensee documents from the licensee's site does not extend to license renewal inspectors.

RECOMMENDATION:

OIG recommends that the Executive Director for Operations:

3. Clarify guidance and adjust procedures for auditors' and inspectors' removal of licensee-provided documents from license renewal sites

C. Consistent Evaluation of Operating Experience Would Improve NRC Reviews

License renewal audit teams have a unique opportunity to improve the NRC license renewal review with a deeper and more consistent approach to reviewing operating experience. Operating experience plays an important role in license renewal, and the license renewal staff is expected to review plant-specific operating experience, including corrective actions. Yet, audit team members do not review operating experience consistently. Furthermore, most audit team members do not conduct independent verification of operating experience, instead relying on licensee-supplied information. This is because program managers have not established requirements and controls to standardize the conduct and depth of such reviews. In the absence of conducting independent verification of plant-specific operating experience, license renewal auditors may not have adequate assurances that relevant operating experience was captured in the licensee's renewal application for NRC's consideration.

The Importance of Operating Experience to License Renewal

Operating experience plays an important role in license renewal and figures prominently in a licensee's renewal application. NRC's *Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants* (Standard Review Plan) instructs NRC staff to assess 10 program elements for each aging management program submitted in a licensee's renewal application. Operating experience is listed as one of these 10 elements, and defined in brief in the *Generic Aging Lessons Learned (GALL) Report* summary as follows:

> *"Operating experience involving the aging management program, including past corrective actions resulting in program enhancements or additional programs, should provide objective evidence to support a determination that the effects of aging will be adequately managed so that the structure and component intended functions will be maintained during the period of extended operation." (p. 2)*

Operating experience is also an important part of two other aging management program elements: specifically, detection of aging effects, and monitoring and trending. The Standard Review Plan also calls attention to the importance of the licensee's plant-specific operating experience in relation to scoping and screening, aging management review, and time-limited aging analyses activities. DLR management also said that it expects its license renewal staff to review plant-specific operating experience, including corrective actions. Given the Standard Review Plan's emphasis on operating experience and on management's expectations, OIG concludes there is ample reason for the licensee to provide—and NRC to review—sufficient amounts of operating experience information and data.

Operating Experience Is Not Consistently Reviewed or Independently Verified

When reviewing aging management programs, license renewal audit team members do not approach their reviews of operating experience consistently and, furthermore, most team members do not conduct independent verification of operating experience. Team members are assigned aging management programs to review based on their areas of expertise. A more experienced reviewer or auditor may look more in-depth at, or conduct independent spot checks of, licensee-submitted information provided in the license renewal application.

OIG asked license renewal auditors and management about the appropriateness of conducting independent searches of licensee operating experience. Such searches might examine the licensees' corrective actions, system health reports, and inspection results. NRR managers said that they expect the audit teams to review plant-specific operating experience. Some managers said they expected license renewal auditors to perform their own searches of corrective actions rather than rely solely on information provided by the licensee.

However, license renewal auditors said that they generally do not conduct independent searches of licensee corrective action databases and that auditors would not normally review a plant's corrective action program for each aging management program because the industry-wide experience is already known. One reviewer said that it is the licensee's responsibility to provide NRC with plant-specific operating experience that is different from industry-wide operating experience. The auditor reviews only what the licensee provided in its application. Another reviewer said that capturing plant-specific operating experience is time-consuming or that it is too difficult to learn how to use the licensees' corrective action program databases.

With the assistance of an OIG technical advisor having a general engineering background, OIG sought to learn how difficult it would be to generate a useful database report of corrective actions. OIG staff visited two separate plants owned by large utility companies and, using computers attached to the respective owners' local area networks, performed keyword searches of the corrective action databases.[17] OIG's technical advisor searched the available network data for the host plant and for several other already renewed plants in their respective fleets.[18]

From these searches, OIG was able to identify a number of areas for each plant that would warrant follow-up questions for licensees regarding past performance of license renewal aging management programs. Given the time to conduct and analyze the database searches, OIG concluded that accessing the corrective action databases was relatively easy and provided access to a good deal of information of potential value to license renewal audit teams. OIG does not believe that the results of such a search would necessarily validate an entire aging management program, but the endeavor does identify a relatively easy way for license renewal auditors to conduct an independent check of the information provided by the licensee.

Requirements to Independently Verify Operating Experience Have Not Been Established

License renewal program managers have not established requirements or controls to standardize the conduct of independent verifications and depth of probes of plant-specific operating experience during audit reviews of licensee applications. That is not to suggest that DLR management has failed to mention the importance of reviewing operating experience to audit teams. On

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[17] Keywords included "corrosion," "cracking," "fatigue," "leak," "pitting," "drywell," "HPCI," "primary containment," "secondary containment," and "Torus."

[18] It is important to note that OIG staff had no previous experience or familiarity using these databases. At both plant sites, OIG staff needed approximately 5 hours total to learn basic search mechanisms for the corrective action databases, and then perform the keyword search for three plants in each fleet.

the contrary, OIG observed DLR management discussing the importance of plant-specific operating experience with license renewal auditors at a team meeting.

DLR management has not set any formal requirements that license renewal audit teams independently verify plant-specific operating experience as a standard part of their reviews. The *Project Team Guidance* handbook instructs reviewers to compare program elements for the plant's aging management programs to the corresponding program elements for GALL-identified aging management programs. But the *Project Team Guidance* handbook does not include any specific direction about how this should be accomplished. Essentially, the guidance leaves a lot of leeway to individual auditors to review operating experience as they see fit.

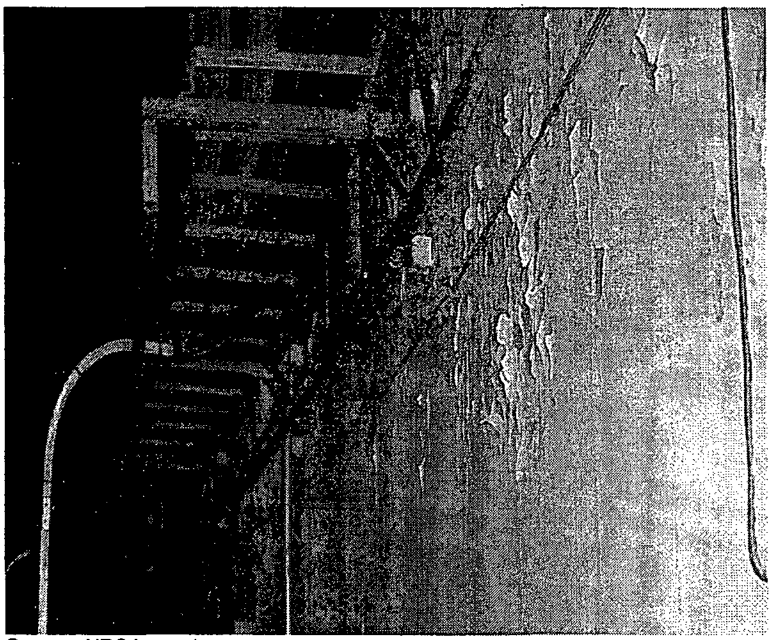
DLR also has no controls to monitor and enforce operating experience verification, which incorporate independent searches of corrective action databases. One manager said that more management controls to bring consistency to the reviews would be welcomed. The manager pointed out that DLR management can require audit teams to perform deeper probes of operating experience, but has no way of determining whether the auditors follow through.

Auditors May Not Be Aware of All Relevant Operating Experience

In the absence of conducting independent verification of plant-specific operating experience, license renewal auditors may not have adequate assurances that all relevant operating experience was captured in the licensee's renewal application. As reported above, OIG was able to identify a number of areas for each plant that would warrant follow-up questions for licensees regarding past performance of license renewal aging management programs.

OIG's work in this area was, in part, informed by a discrepancy noted while reviewing the Oconee license renewal application. NRC received the Oconee plant's license renewal application in July 1998, whereupon the application remained under review until renewal was granted in May 2000. The application stated that minor local containment coatings failures had been observed and repaired. Yet, the Oconee corrective action program contained 20 entries for degraded coatings from 1995-2003.[19] OIG's analysis of this corrective action program indicates that the coatings aging management program had not been implemented consistent with the statements in the Oconee license renewal application. In fact, coatings degradation was a continuing problem at the Oconee Nuclear Station as of Spring 2004, the date of the photograph presented in Figure 4 below, casting doubt on the efficacy of Oconee's aging management program for coatings.

Figure 4
Example of Coatings Degradation at Oconee



Source: NRC Inspector

NRC license renewal reports do not indicate that NRC reviewers independently verified Oconee's operating experience for coatings. The license renewal inspection report states that the inspection included a review of the program description documents and discussion of the program with a site engineer. The inspection report concluded, based on the program document review and the

[19] Six of the entries were made prior to the submittal of the license renewal application in 1998. Two of the entries were made after the renewal application was submitted, but prior to the granting of the renewed license in May of 2000.

discussion, that the "team verified that this previously existing program was implemented as described in the [license renewal application]." The license renewal safety evaluation report for Oconee quotes or paraphrases passages from the Oconee renewal application, including the licensee's conclusion that the program is based on well-established industry standards and has been revised as necessary on the basis of plant experience. The staff acknowledged in the safety evaluation report that the licensee did not provide coatings program operating experience in its application, yet the staff did not offer any indication of having conducted an independent look at coatings operating experience.

OIG contends that a quickly-performed, independent search of the Oconee corrective action database would have revealed discrepancies with the information and assessment provided by the licensee in the renewal application. Such a search would have generated the corrective action reports that described continuing coatings problems and raised questions about the licensee's contention that minor local containment coatings failures have been observed and repaired. Moreover, performing and documenting this type of search helps NRC prevent the appearance that license renewal reviewers trust information provided by the licensee in the renewal application without verification.

RECOMMENDATION:

OIG recommends that the Executive Director for Operations:

4. Establish requirements and management controls to standardize the conduct and depth of license renewal operating experience reviews.

D. More Attention Is Needed to Planning for Post-Renewal Inspections

NRC considers post-renewal inspections vital to ensure that licensees adhered to commitments made for license renewal.[20] However, post-renewal inspection planning is incomplete because the agency has only recently focused its attention on developing and overseeing details associated with these inspections. Inadequate planning increases the risk that: licensees could enter into the extended period of operation without being in full compliance with license renewal terms; inspections will be inconsistently implemented; and inspection and technical support resources will be unavailable when needed.

Timely Inspection Planning Is Essential

Post-renewal inspections will play a vital role in ensuring that licensees followed through on their license renewal commitments and, therefore, thorough planning for these inspections is essential. Regional inspection guidance states that the best inspection plans are prepared well in advance, list clear expectations, and should be developed by working closely with the key customers – for license renewal that means NRC and licensee staffs. Thorough planning would help ensure appropriate inspection resource needs are met and bring consistency to the implementation of the post-renewal inspections.

Post-Renewal Inspection Details Are Not Fully Developed

Despite the importance of planning for the required post-renewal inspections, details have not been fully developed. Inspection Manual Chapter 2516[21] states that a post-renewal inspection, in accordance with Inspection Procedure 71003, *Post-Approval Site Inspection for License Renewal,* will be conducted at sites receiving an NRC-approved license extension. Inspection Manual Chapter 2516 also identifies NRR as the organization responsible for

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[20] NRC established a two-phase license renewal inspection program: the phase one inspections occur during the safety review process and phase two consists of post-renewal inspections (i.e., after NRC has granted the license extension). Planning for the post-renewal inspections is the focus of this report section.

[21] Inspection Manual Chapter 2516, *Policy and Guidance for the License Renewal Inspection Programs.*

planning and overseeing license renewal inspections. NRC's four regions are then responsible for implementing the inspections. Although the agency has initiated a revision to Inspection Procedure 71003, details regarding the scope, timing, and resource determinations of these inspections have not been specified or fully developed. NRC anticipates that all relevant issues will be addressed in the revised procedure.

Undefined Scope

Inspection Procedure 71003 states that the purpose of post-renewal inspections is to verify that licensees implemented renewal aging management programs and activities in accordance with: the requirements of 10 CFR Part 54; renewal-specific license commitments; and NRC's safety evaluation report. However, the inspection procedure as written does not give the specifics of the breadth and scope expected of these inspections, such as:

- the sample size of the aging management programs or licensee commitments to be inspected;
- whether there are licensee commitments and aging management programs established after the application was approved that must be included in the sample;
- whether inspectors must have headquarters' concurrence on potentially unresolved commitments, who in NRR should be contacted and how, and when that interaction should occur; and
- who determines, and on what basis, whether the licensee continues to meet the commitments required for operating into the extended period.

Timing of Post-Renewal Inspections is Not Clearly Understood

Timing of the post-renewal inspections is critical because NRC will use the results to determine whether a licensee can safely continue to operate into an extended period. However, Inspection Procedure 71003 gives a broad range for, and NRC's written and verbal expectations vary on, the timing required for conducting the post-renewal inspections. As a result, region staff and licensees do not have sufficient detailed information needed to plan for the upcoming post-renewal inspections even though the first of these inspections are due in calendar year 2009. It is important that the revision to Inspection Procedure 71003 provide the necessary details.

Regional Impact

Inspection Procedure 71003 states that post-renewal inspections should be implemented *either before or shortly after the commencement of the extended period of operation.* Yet, another agency document says that the post-renewal inspections will be performed *'in the vicinity of' the period of extended operation – within a year prior to or following the extended license taking effect.* Neither document defines the basis for the time periods established for conducting these inspections. [emphasis added]

NRC expects the number of new license renewal applications requiring NRC inspections to peak in FY 2009. The peak in new license renewal activity coincides with the timeframe for conducting the first post-renewal inspections. Because region-based inspectors are not dedicated solely to license renewal matters, the post-renewal inspection activities must be factored into their overall inspection schedules. The regions' inspection planning horizon is 18 months. NRC's FY 2009 proposed budget includes a request for the regions to conduct the needed post-renewal inspections.

Licensee Impact

For planning and budgeting purposes, industry representatives from the Nuclear Energy Institute (NEI) and licensee organizations have repeatedly requested that NRC provide more specific details on the post-renewal inspections. At a January 2007 NRC/NEI interface meeting, industry again requested detailed information regarding NRC's expectations for implementing these inspections. An NRC senior manager responded that the details, including the timeline, for the post-renewal inspections are "being worked on but as yet there is no schedule defined."

In addition, industry and NRC managers, as well as inspection staff, have expressed different positions with regard to the timing of the post-renewal inspections, including when license renewal commitments must be ready for NRC's post-renewal inspection.

The following paraphrased exchange between a licensee and NRC license renewal senior managers at the January 2007 NRC/NEI meeting demonstrates NRC's inconsistent expectations:

> *A renewal licensee expressed confusion over the timing of the 71003 inspections. According to the licensee, an NRC regional lead inspector announced that post-renewal inspections in one region will occur in 2008 even though the original license in question does not expire until sometime in 2009. A senior DLR manager responded that licensees technically have until the end of the full 40-year license to meet the conditions of the license extension. However, another key license renewal manager countered that renewal commitments should be completed 2 years before license expiration so that NRC can verify the commitments are effective before licensees enter the extended period of operation.*

Inspection Resource Needs Are Not Fully Developed

Agency managers acknowledge that resource planning for the post-renewal inspections is important. However, agency managers acknowledge that post-renewal inspection staffing and budget needs have not been fully developed. Furthermore, management questions whether information needed to prepare accurate post-renewal inspection budget requests will be available in a timely manner.

License renewal program management told OIG that planning for the post-renewal inspections is not only important, but particularly timely given the recent request for the NRR's FY 2009 budget needs. However, as stated above, the regions have not yet factored these inspections into the overall inspection schedule and planning is hindered because there is not consensus on what resources will be needed. For example, Inspection Procedure 71003 estimates that the post-renewal inspection teams will consist of five members — four inspectors and a team leader. The inspection procedure also estimates that each inspection will take 5 to 6 weeks, including 2 weeks on-site, and require about .52 full-time equivalents. Although acknowledging that none of these inspections have occurred as yet, a senior region manager responsible for inspection program scheduling and oversight estimates that it will take half the time on-site and twice the resources to perform the post-renewal inspections given the narrowly defined scope in Inspection Procedure 71003.

There is also no indication that the resource estimates established in Inspection Procedure 71003 factor in the potential need for multiple rounds of inspections and/or the time needed should the inspectors require headquarters technical support for issue resolution. Because NRR has not finalized the details about the scope, timing, and responsibilities for the post-renewal inspections, it is questionable whether an accurate and meaningful budget request can be prepared. It is necessary that the revision to Inspection Procedure 71003 address these issues.

Improved Organizational Focus Is Needed

Post-renewal inspection planning is incomplete because management has not focused its attention on developing and overseeing plans for this future activity. Until recently, there had been little discussion between NRR senior managers and those ultimately responsible for implementing and preparing for the post-renewal inspections, namely region-based inspectors and licensees.

NRR is responsible for the development and implementation of license renewal programs and activities, and is responsible for technical and inspection support. According to agency managers and staff, the reason why NRR managers have not focused attention on planning the details of Inspection Procedure 71003 is because the post-renewal inspections are viewed as activities outside of license renewal space and because these inspections would not occur for several more years. NRR notes that it started an effort to revise Inspection Procedure 71003 in the summer of 2006.

Challenges Associated with Incomplete Planning

Using under-developed Inspection Procedure 71003 for planning the post-renewal inspections would result in some risks and management challenges that could hamper the efficiency and effectiveness of the license renewal program. The most significant concern is that licensees could potentially begin operating into the extended period without being in full compliance with the terms or intent of their renewed license.

Planning for the specific timing of the post-renewal inspections is important because inspectors are expected to verify license renewal commitments that must be in place and accepted before the end of the original operating period. Otherwise NRC may be at risk of allowing a plant to enter into an extended period of operation in noncompliance with the terms or intent of the renewed license. This risk would be particularly acute for licensees with outstanding commitments to develop and implement new aging management programs years after their license renewal applications were reviewed and approved. There is no consideration in the license renewal process for subjecting new aging management programs to the same type of technical sufficiency reviews as existing aging management programs. Therefore, scheduling the post-renewal inspections needed to confirm the existence or implementation of the new aging management programs *after* the period of extended operation has begun exacerbates these risks.

The lack of a detailed and standardized inspection methodology could also lead to inconsistent post-renewal inspections. Without this planning, there exists the potential that individual inspectors—or, at a minimum, each region—will devise their own inspection methodology and may not receive the information needed to develop site-specific, comprehensive inspection plans, such as which version of the *GALL Report* and other agency requirements applies for each inspection.

Finally, without the information needed to adequately make the budget and staffing determinations, the license renewal program could be left vulnerable to unanticipated budget and staffing shifts. This major challenge, voiced by NRC and industry alike, concerns whether necessary inspection resources will be available when the time comes to implement the post-renewal inspections.

RECOMMENDATIONS:

OIG recommends that the Executive Director for Operations:

5. Expedite completion of the details for a revised Inspection Procedure 71003.

6. Communicate the details of revised Inspection Procedure 71003 to all applicable staff and stakeholders.

E. License Renewal Issues Need Evaluation for Backfit Application

When NRC imposes new staff positions resulting in new license renewal review standards, a documented justification is required pursuant to the backfit rule. However, new license renewal review standards have not followed NRC's backfit policy. This condition exists because NRC does not have a mechanism or methodology to trigger a backfit review. Additionally, NRR has not designated any organizational accountability for performing license renewal-related backfit justifications. Consequently, the use of different review standards without a backfit justification may result in several management challenges.

Backfit Requirements

The *Code of Federal Regulations*, under 10 CFR 50.109, defines backfitting to include new or different staff positions that require changes to things such as designs, plant equipment, and procedures. As shown below, the regulation also requires that staff document its justification for imposing a backfit regardless of which justification is cited:

- a "documented evaluation" is required when backfitting is justified (1) for compliance, (2) as necessary for adequate protection, or (3) as needed to redefine adequate protection. The documented evaluation must include a statement of the objectives and reasons for the change and a basis for invoking either a compliance exception or adequate protection exception, whereas

- a "systematic and documented analysis," which includes a cost-benefit analysis, is required when the NRC claims a substantial increase in public health and safety justifies the cost of a backfit.

New Staff Positions Are Not Reviewed for Backfit Consideration

NRC captures new insights or emerging issues during license renewal reviews and from operating reactor performance. These new insights or issues may lead to a new staff position that results in a new review standard. However, the staff's position is that the backfit rule does not apply to license renewal applicants based on exceptions in 10 CFR 54.37(b) and a 1995 Commission Statement of Considerations (SOC) published with promulgation of the License Renewal Rule. Therefore, new license renewal standards are not reviewed and documented for backfit considerations because there is no identified procedure to do so.

New staff positions are documented in Interim Staff Guidance (ISG) documents. ISGs are used to communicate new NRC review standards to renewal applicants and other interested stakeholders until the emerging issues can be incorporated into the next revision of the license renewal guidance documents, particularly the *GALL Report* – the primary license renewal guidance document. There are two types of ISG documents: clarification and compliance.

According to the agency, clarification ISGs provide additional guidance to renewal applicants to improve the efficiency and effectiveness of the license renewal process, and thereby do not create new staff positions and do not apply to licensees holding renewal licenses. On the other hand, compliance ISGs involve meeting the requirements of 10 CFR 54.37(b) and, therefore, do apply to both applicants and licensees holding renewed licenses. The agency further states that the only ISGs applicable to holders of renewed licenses are those compliance ISGs involving "newly identified" SSCs that should be in the scope of license renewal in accordance with 10 CFR 54.37(b). Finally, the agency concludes that requiring licensees to consider aging management for newly identified SSCs after a license is renewed is not a backfit issue.

In November 2006, NRC issued LR-ISG-2006-01[22] as a "clarification" ISG. The ISG requires current and future license renewal applicants to add a new aging management program in their applications to address inaccessible areas of the Mark I steel containment drywell shell. By requiring a new aging management program, this ISG went beyond providing "additional guidance" as intended with a clarification ISG. Additionally, the steel containment drywell shell is not a newly-identified area but is an SSC already within the scope of license renewal reviews. Furthermore, there was no documented evaluation or analysis

[22] LR-ISG-2006-01, *Plant-Specific Aging Management Program for Inaccessible Areas of BWR Mark I Steel Containment Drywell Shell,* dated November 2006.

justifying whether NRC's new position should be backfit to already renewed licenses. Consequently, plants renewed prior to November 2006 may manage aging effects of drywell shells to a different standard. Finally, OIG concludes that using LR-ISG-2006-01 to change the review standard of drywell shell aging management represents a miscategorization of this ISG as a "clarification" rather than a "compliance" issue.

Renewal Review Process Does Not Trigger Backfit Evaluations

Although NRC senior managers confirmed that new staff positions should be properly justified and they expect that they are, the staff has not justified ISGs as required by NRC's backfit rule. OIG found that there is no mechanism in the license renewal review process to trigger documented backfit justifications of ISGs, nor is there a methodology for conducting such evaluations or analysis of ISGs and the new standards they impose.

OIG's examination of license renewal guidance documents also determined that the organizational accountability for these documented justifications has not been clearly established. NRC managers and staff gave OIG inconsistent information about where the backfit reviews should be assigned. In fact, senior managers identified different NRR organizations as currently accountable for backfit justifications, none of which conduct backfit reviews.

Challenges Associated With Unjustified, Nonuniform Review Standards

NRC's use of different review standards without justification from a backfit evaluation or analysis may result in the following management challenges:

- the appearance that previous approval standards may have been inadequate,
- stakeholders questioning continually changing review standards, and
- licensees managing aging effects differently from plant-to-plant.

Appearance that Previous Approval Standards May Have Been Inadequate

Because ISGs do not receive backfit reviews, there may be an appearance that inadequate standards were applied to previously approved license renewal applications. As a result, NRC may be vulnerable to questions about the adequacy of its approval process and the adequacy of those aging management programs already approved.

Stakeholders Question Continually Changing Review Standards

Licensees have questioned the basis for NRC's application of different review standards in the absence of justification through backfit reviews. The agency portrays the license renewal program as a living process to be updated for improvement as experience is gained. Industry representatives acknowledge the value of process improvements, but question the basis for NRC's continually changing requirements as reflected in the following statement from an industry license renewal vice president:

> *If submissions were good enough before but not now [given NRC's issuance of new standards], does that mean that the previously approved applications did not really have enough substance to be granted a renewed license?*

Using the backfit process as an integral part of ISG reviews would explain and justify NRC's changing positions and hopefully eliminate licensee questions about NRC's different review standards.

Licensees May Manage Aging Effects Differently from Plant-to-Plant

The lack of a systematic application of the backfit process also raises potential safety questions when plants manage the same aging effects differently without a specific justification. This is particularly true when NRC identifies a system or component that needs a new aging management program, then requires current and future license renewal applicants to address the newly-identified issue, but does not require already approved licensees to do the same.

RECOMMENDATIONS:

OIG recommends that the Executive Director for Operations:

7. Establish a review process to determine whether or not Interim Staff Guidance meets the provisions of 10 CFR 54.37(b), and document accordingly.

OIG recommends that the Commission:

8. Affirm or modify the 1995 Commission's Statement of Considerations position regarding the applicability of the backfit rule to license renewal applicants.

IV. CONSOLIDATED LIST OF RECOMMENDATIONS

OIG recommends that the Executive Director for Operations:

1. Establish report-writing standards in the *Project Team Guidance* for describing the license renewal review methodology and providing support for conclusions in the license renewal reports.

2. Revise the report quality assurance process for license renewal report review to include:

    - establishing management controls for NRR and DLR management to gauge the effectiveness of team leader and peer group report reviews, and

    - implementing procedures that would specify additional report quality assurance steps to be taken in the event that the team leader and peer group report reviews fail to ensure report quality to management's expectations.

3. Clarify guidance and adjust procedures for auditors' and inspectors' removal of licensee-provided documents from license renewal sites.

4. Establish requirements and management controls to standardize the conduct and depth of license renewal operating experience reviews.

5. Expedite completion of the details for a revised Inspection Procedure 71003.

6. Communicate the details of revised Inspection Procedure 71003 to all applicable staff and stakeholders.

7. Establish a review process to determine whether or not Interim Staff Guidance meets the provisions of 10 CFR 54.37(b), and document accordingly.

OIG recommends that the Commission:

8. Affirm or modify the 1995 Commission's Statement of Considerations position regarding the applicability of the backfit rule to license renewal applicants.

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V. AGENCY COMMENTS

On May 8, 2007, OIG issued its draft report to the Executive Director for Operations. OIG subsequently met with managers from DLR and OGC to address specific issues and concerns needing further clarification and/or explanation. On July 6, 2007, the Deputy Executive Director for Reactor Programs provided a formal response to this report in which the agency disagreed with OIG's finding regarding applicability of the backfit rule to license renewal applicants. The agency's transmittal letter and specific comments on this report are included in their entirety as Appendix E.

The staff's position is that 10 CFR 50.109, "Backfitting," does <u>not</u> apply to license renewal (for holders of renewed licenses) with respect to <u>new</u> structures, systems or components (SSC) brought within the scope of the license renewal rule as required by 10 CFR 54.37(b). Conversely, the agency acknowledges that the backfit rule does generally apply for SSCs that *were or should have been reviewed during the scope of license renewal review.* [emphasis added] OIG generally concurs with these two positions, although OIG determined that the agency does not have a process to identify whether ISGs meet the provisions in 10 CFR 54.37(b) thereby making them exempt from backfitting.

However, OIG disagrees with the staff's position that the backfitting rule does not apply to license renewal applicants based on exceptions in 10 CFR 54.37(b) and the 1995 SOC published with promulgation of the License Renewal Rule. OIG believes that the plain language of the backfit regulation states that the backfit rule <u>is</u> applicable to holders of an operating license, which by default includes applicants seeking a renewed license.[23] OIG found no exception or provision in either the backfit rule or the License Renewal Rule that suspends applicability of the rule to license renewal "applicants" or the information in their renewal applications. Consequently, the sole regulatory basis for the staff's position that backfitting does not apply to applicants is the 1995 SOC.

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[23] 10 CFR 50.109(a)(1)(iii).

OIG notes that the 1995 Commission's SOC position is 12 years old and was written prior to any license renewal applications being processed. NRC has now processed 48 license extensions. Based on this experience, the SOC needs to be reevaluated.

This final report incorporates revisions made, where appropriate, as a result of the subsequent meetings and the agency's written comments. In addition, based on the agency's response, OIG revised and redirected Recommendation 8 to request that the Commission affirm or modify the 1995 Commission's Statement of Considerations position regarding the applicability of the backfit rule to license renewal applicants. Appendix F contains OIG's complete analysis of the agency's formal response.

Appendix A

SCOPE AND METHODOLOGY

NRC's license renewal review process follows two paths: safety and environmental. The focus of this audit was to determine the effectiveness of NRC's license renewal safety reviews. To address the audit objective, OIG reviewed relevant management controls, related documentation from internal and external sources, and Federal statutes, including reviews of:

- The Atomic Energy Act of 1954
- NEI 95-10, *Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule*
- Licensee Corrective Action Program databases
- *Code of Federal Regulations*, Title 10, Parts 50, 51 and 54
- NRR/Division of License Renewal *Project Team Guidance*
- NRR's *Self Assessment of License Renewal Application Improved Safety Review Process*
- Inspection Manual Chapters (IMC)
  - IMC 0620, *Inspection Documents and Records*
  - IMC 2516, *Policy and Guidance for the License Renewal Inspection Programs*
  - Inspection Procedures 71002 and 71003
- Regulatory Guides 1.147 and 1.188
- Management Directive 8.4, *Management of Facility-specific Backfitting and Information Collection*
- NUREGs, including:
  - NUREG-1800, *Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,* and

- NUREG-1801, *Generic Aging Lessons Learned (GALL) Report*

Auditors conducted interviews with more than 50 agency and industry individuals, including:

- NRC senior managers and staff from:
  - Headquarters, Rockville, Maryland
  - Region I, King of Prussia, Pennsylvania
  - Region II, Atlanta, Georgia
  - Region III, Lisle, Illinois
  - Region IV, Arlington, Texas

- OGC and ACRS members at NRC Headquarters

- Industry representatives and plant personnel from:
  - The Nuclear Energy Institute
  - Exelon Nuclear
  - Entergy Nuclear

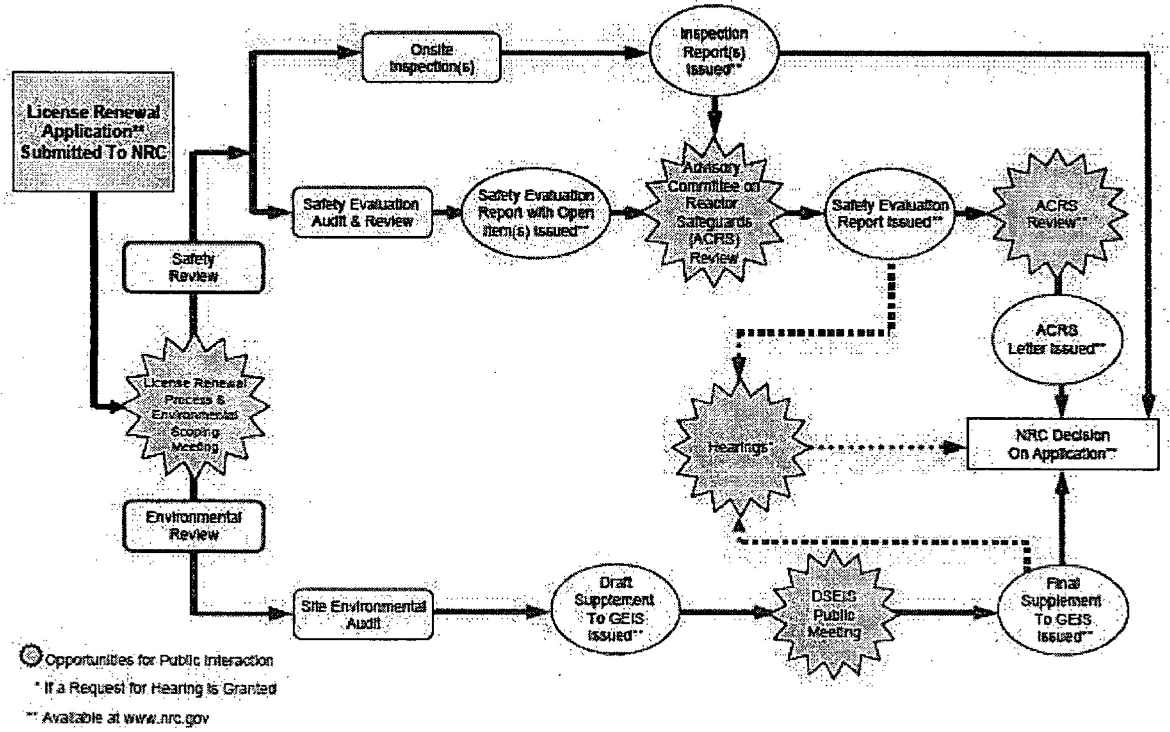
OIG conducted this audit between March 2006 and December 2006 in accordance with generally accepted Government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

The major contributors to this report were Anthony Lipuma, Team Leader; Catherine Colleli, Audit Manager; Robert K. Wild, Senior Management Analyst; Michael Cash, Senior Technical Advisor; and Jaclyn Storch, Management Analyst.

Appendix B

NRC'S DUAL-TRACK LICENSE RENEWAL REVIEW PROCESS

License Renewal Process



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Appendix C

OIG CONTENT ANALYSIS

OIG performed a content analysis of audit reports, inspection reports, and safety evaluation reports for a judgmental sample of license renewal applications submitted between September 2000 and January 2006.[24] The judgmental sample of license renewal applications represents a cross-section of plant ages, technologies, year of renewal, NRC review method, and NRC region. For the review, OIG focused on narrative passages in the applications and reports that addressed the operating experience program element for a selection of aging management programs.[25] The OIG sample generated 458 data points reflecting how the license renewal auditor's methodology and support for conclusions was addressed in the audit, inspection, and safety evaluation reports, as shown in the following table:

[24] OIG chose a judgmental sample in order to assure a mix of different plant types and renewal program experience. Consequently, this report presents findings related to the sample only and does not extrapolate results from the sample to the entire universe of renewal reviews.

[25] Not all aging management programs were reviewed in OIG's analysis. OIG selected 11 aging management programs for its content analysis and each of these 11 aging management programs were reviewed for each sampled plant for consistency. As a result, some aging management programs did not apply to a plant, and in such cases OIG did not create a data point for that plant. Moreover, OIG acknowledges the possibility that aging management programs not reviewed could have scored differently than the results indicated in OIG's report.

Table 2
Summary of OIG Analysis of Report Documentation for the GALL Operating Experience Program Element

Application	LRA [a] Date	Data Points Total	Green	Yellow	Red
Vermont Yankee	2006	12	0	12	0
Oyster Creek	2005	40	0	34	6
Palisades	2005	42	4	29	9
Monticello	2005	28	1	23	4
Millstone	2004	46	0	34	12
Browns Ferry	2004	40	1	22	17
Brunswick	2004	42	2	30	10
Point Beach	2004	38	2	30	6
D.C. Cook	2003	50	1	37	12
Dresden/Quad Cities	2003	42	0	11	31
Ginna	2002	42	0	8	34
St. Lucie	2001	20	0	10	10
Turkey Point	2000	16	0	8	8
Total		458	11	288	159
Percent		100%	2.4%	62.9%	34.7%

Source: OIG analysis of NRC license renewal audit, inspection, and safety evaluation reports; and of licensee renewal applications. [b]

Notes:

a. License Renewal Application.
b. The number of data points by application varies owing to applicability of individual aging management programs. Some of the older applications pre-date the DLR audit function, and there was no inspection report or safety evaluation report yet available for Vermont Yankee at the time of OIG's analysis.

Table 2 provides subjective "red," "yellow," and "green" ratings, which reflect the extent to which review methodology is disclosed and staff conclusions are supported in the reports.

- A red rating indicates, for an aging management program reviewed by NRC, that there was no mention of review methodology or no specific support for the staff's conclusions in the audit, inspection, or safety evaluation reports.

- A yellow rating indicates, for an aging management program reviewed by NRC, that the audit, inspection, or safety evaluation reports cited anecdotal information provided by the licensee or restated language from the license renewal application to support staff conclusions. A yellow rating also indicates that the methodology reported was limited to reviewing the license renewal application and interviewing licensee personnel, or to reviewing anecdotal information provided by the licensee.

- A green rating indicates, for an NRC-reviewed aging management program, that the audit, inspection, or safety evaluation reports provided details regarding the staff's review methodology beyond a simple review of the license renewal application or anecdotal information provided by the licensee. The green rating also indicates that the staff provided detailed and independent support for their conclusions in the report.

OIG conducted additional analysis of the yellow data points to determine how closely the application information that was restated in the license renewal reports resembled the original information provided in the applicable license renewal application. OIG found that 191 of the 288 yellow data points, or 41.7 percent of the total 458 data points, were identical or nearly identical to the information provided in the license renewal application. Examples of original license renewal application text being repeated in an NRC document with no or few clues to indicate to the reader that it is repeated prose are provided in Appendix D.

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Appendix D

EXAMPLES OF LICENSE RENEWAL APPLICATION TEXT REPEATED IN NRC DOCUMENTS

Original License Renewal Application Text	NRC License Renewal Report Text
Operating experience of Flow-Accelerated Corrosion aging management program activities has shown that the program can determine susceptible locations for flow accelerated corrosion, predict the component degradation, and detect the wall thinning in piping, valves, and Feedwater Heater shells due to flow-accelerated corrosion. In addition, the program provides for reevaluation, repair or replacement for locations where calculations indicate an area will reach minimum allowable thickness before the next inspection. Periodic self-assessments of the program have been performed which have identified opportunities for program improvements. (Oyster Creek LRA [a], p. B-41.)	Operating experience of the Flow-Accelerated Corrosion Program activities shows that the program can determine susceptible locations for Flow-Accelerated Corrosion, predict the component degradation, and detect the wall thinning in piping, valves, and feedwater heater shells due to Flow-Accelerated Corrosion. In addition, the program provides for reevaluation, repair, or replacement for locations where calculations indicate an area will reach minimum allowable thickness before the next inspection. Periodic self-assessments of the program have been performed which have identified opportunities for program improvements. (NRC's SER [b] with Open Items for Oyster Creek, p. 3-14.)
The OE review shows that the BSEP Bolting Integrity Program is continually upgraded based on industry experience, research, and routine program performance. The Program, through its continual improvement, assures the capability of mechanical bolting to support the safe operation of BSEP throughout the extended period of operation. (Brunswick LRA, p. B-24)	The applicant also states that the operating experience review shows that its bolting integrity program is continually upgraded based on industry experience, research, and routine program performance. The program, through its continual improvement, assures the capability of mechanical bolting to support the safe operation of BSEP throughout the extended period of operation. (NRC's Audit Report for Brunswick, p. 39)
The fire water system parameters are monitored, tested and piping and component evaluations are performed to ensure that the system maintains its intended function. Browns Ferry Fire Water System operating experience indicates a trend of piping degradation, such as leaks, general corrosion, biofouling, etc. Piping is being replaced, as required, per corrective actions of the inspection and testing activities. (Browns Ferry LRA, p. B-76)	In LRA Section B.2.1.24, the applicant stated that the fire water system parameters are monitored and tested, and that piping and component evaluations are performed to ensure that the system maintains its intended function. The BFN Fire Water System operating experience indicates a trend of piping degradation, such as leaks, general corrosion, and biofouling, etc. Piping is being replaced, as required, in accordance with corrective actions of the inspection and testing activities. (NRC's SER for Browns Ferry, p. 3-70)
A review of operating experience pertaining to the Oil Analysis Program determined that program enhancements have been made based on industry and plant-specific operating experience. For example, the potential for possible incompatibility between emergency diesel generator fuel oil and lube oil identified at Calvert Cliffs Nuclear Power Plant was evaluated and a program change was made to ensure the problem was addressed at CNP. The review of condition reports indicates that the program has detected conditions at levels below which aging degradation is expected to occur. (D.C. Cook LRA, p. B-77)	The applicant states in CNP AMP [c] B.1.23, for the operating experience program element, that a review of operating experience pertaining to this AMP determined that program enhancements have been made based on industry and plant-specific operating experience. For example, the potential for possible incompatibility between emergency diesel generator fuel oil and lube oil identified at another nuclear power plant was evaluated and a program change was made to ensure the problem was addressed. The review of condition reports indicates that the program has detected conditions at levels below which aging degradation is expected to occur. (NRC's Audit Report for D.C. Cook, p. 68)

Source: OIG analysis of NRC license renewal audit, inspection, and safety evaluation reports; and of license renewal applications.

<u>Notes</u>:

a. license renewal application
b. safety evaluation report
c. aging management program

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Appendix E

FORMAL AGENCY COMMENTS

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

July 6, 2007

MEMORANDUM TO: Stephen D. Dingbaum
Assistant Inspector General for Audits
Office of the Inspector General

FROM: William F. Kane
Deputy Executive Director for Reactor Programs

SUBJECT: COMMENTS ON DRAFT REPORT – "AUDIT OF NRC'S LICENSE RENEWAL PROGRAM"

We are responding to your June 22, 2007, memorandum transmitting the Office of the Inspector General's (OIG's) Draft Audit Report, "Audit of NRC's License Renewal Program." We appreciate the significant time spent by the OIG staff in observing and evaluating the operating reactor license renewal program and the OIG's recommendations for improving the program. As communicated to the OIG staff at the exit conference and in related discussions, the NRC staff disagrees with OIG's conclusions in Finding E that the Interim Staff Guidance (ISG) documents require backfit justifications in accordance with Title 10 of the Code of Federal Regulations (10 CFR) Section 50.109, "Backfitting," and OIG Recommendations 7 and 8 that the NRC needs to establish a process for performing backfit analyses for ISG documents. This memorandum provides the bases for the staff's position that backfit analyses are not required for ISG documents.

The purpose of the ISG process is to provide timely dissemination of the latest guidance resulting from lessons learned from ongoing license renewal application reviews until the information can be incorporated in the next update of the NRC's license renewal guidance documents (i.e., Regulatory Guide 1.188; Standard Review Plan, NUREG-1800; or Generic Aging Lessons Learned (GALL) Report, NUREG-1801) as applicable. The ISG process was developed with significant participation by the industry with opportunity for public involvement. A description of the ISG process was issued in final form on December 12, 2003, "The Interim Staff Guidance Process" (ML023520620). The Office of the General Counsel (OGC) participated in developing the ISG process and reviews every ISG document issued by the staff. All proposed ISG documents are published in the *Federal Register* for public comment and are sent by letter to the Nuclear Energy Institute (NEI) and public interest groups for comment. Potential ISG documents are discussed in the monthly public conference calls or meetings held with NEI prior to developing the proposed ISG document.

The NRC's Committee to Review Generic Requirements (CRGR) is chartered to ensure that proposed requirements for licensed power reactors are appropriately justified on the bases of NRC's regulations and the Commission's policy on backfit provisions. The CRGR was initially briefed on the license renewal ISG process on August 26, 2003, as documented in the September 23, 2003, meeting summary "Minutes of the Committee to Review Generic Requirements Meeting Number 389" (ML032670732). The CRGR had no objection to the ISG process, and improvements recommended by the CRGR were incorporated. The staff discussed the ISG process with the CRGR again on September 13, 2005, as documented

S. Dingbaum -2-

In the September 26, 2005, meeting summary "Minutes of the Committee to Review Generic Requirements Meeting Nuclear 403" (ML052660027). In these meeting minutes, the CRGR explicitly stated the following:

> The Committee endorses the staff's position in the ISG process for license renewal, that there is no backfit regarding implementation of the requirements of 10 CFR 54.37(b). The provisions of the backfit rule, 10 CFR 50.109, will continue to apply for imposition of changes on holders of renewed licenses for changes that are outside the scope of 10 CFR 54.37(b).

The staff has consistently stated that any changes required by holders of renewed licenses outside the scope of 10 CFR 54.37(b) require a backfit justification in accordance with 10 CFR 50.109. This position is clearly stated in Section 4.2.5 of the ISG process. As discussed further below, there have been no ISG documents issued that affect holders of renewed licenses other than three ISG documents falling within the scope of 10 CFR 54.37(b). If a change is required in the future by a holder of a renewed license that is outside the scope of 10 CFR 54.37(b), the Office of Nuclear Reactor Regulation (NRR) has existing procedures in place to ensure that backfit requirements are met.

There are two types of ISG documents: clarification and compliance. Clarification ISG documents provide additional guidance to applicants that the staff or stakeholders feel is necessary to improve the efficiency and effectiveness of the license renewal process or to help reduce the number of requests for additional information. Clarification ISG documents do not create new staff positions and do not apply to licensees holding renewed licenses. Clarification ISG documents, like regulatory guides and standard review plans, are not requirements but provide an approach that the staff has found acceptable for complying with the regulations. Applicants may propose and justify approaches other than those contained in the ISG document or the other guidance documents. For holders of renewed licenses, the information addressed by clarification ISG documents, if applicable to the plant, was either provided originally by the applicant in its license renewal application or obtained during the review, for example, by requests for additional information. Compliance ISG documents involve compliance with the requirements of 10 CFR 54.37(b) and, therefore, apply to both applicants and licensees holding renewed licenses. An example of a clarification ISG document is ISG-04, "Aging Management of Fire Protection Systems for License Renewal" (ML022260137), which clarified the aging management programs for fire protection systems described in the GALL Report. A compliance ISG document example involving a newly identified component within the scope of 10 CFR 54.37(b) is ISG-05 "On the Identification and Treatment of Electrical Fuse Holders for License Renewal" (ML030690492).

For license renewal applications currently under review, a backfit analysis is not required for either a clarification or a compliance ISG document. The Commission clearly stated that the backfit rule does not apply to license renewal reviews when it issued the amended license renewal rule, 10 CFR Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," in 1995 (Volume 60, *Federal Register*, at 22490-22491). The Commission determined that a special provision in 10 CFR Part 54 that would impose backfit-style requirements on the agency is not needed. Any additional requirements necessary to manage the effects of aging in order to maintain the plant's current licensing basis may be imposed as

S. Dingbaum -3-

part of the license renewal process. The Commission stated that it does not intend to impose requirements on a licensee that go beyond what is necessary to adequately manage aging. This position is analogous to the compliance exception of 10 CFR 50.109(a)(4)(i).

Once a renewed license is issued, the only ISG documents that apply to a holder of a renewed license are compliance ISG documents that involve newly identified systems, structures, and components (SSCs) that should be in the scope of license renewal in accordance with 10 CFR 54.37(b). In 10 CFR 54.37(b), the Commission addressed SSCs newly identified after issuance of the renewed licenses that would have been subject to an aging management review if they had been identified at the time of the license renewal application. Requiring a licensee to consider aging management for newly identified SSCs after a renewed license is issued is required by 10 CFR 54.37(b) and is not a backfit. The implementation of the requirements of 10 CFR 54.37(b) and the applicability of the backfit rule have been the subject of significant interactions between the NRC staff and the industry. The staff's position, endorsed by OGC, and a discussion of these interactions are contained in an October 11, 2006, NRC letter to NEI, "Response to the Nuclear Energy Institute Regarding Implementation of the Requirements of 10 CFR 54.37(b)" (ML062700236). As previously discussed, the staff's position on implementing the requirements of 10 CFR 54.37(b) was endorsed by CRGR.

Once a renewed license is issued, the plant returns to the normal oversight of the operating reactor program and is no longer within the license renewal program. Responsibility for ensuring compliance with the backfit rule for any new requirements imposed on a licensee is an existing and ongoing requirement for the project manager assigned to each plant within the NRR's Division of Operating Reactor Licensing (DORL). Existing procedures, such as NRR Office Instruction LIC-202, "Procedures For Managing Plant-Specific Backfits and 50.54(f) Information Requests" (ML061720504), provide guidance to the staff on implementing the backfit rule. Any changes that need to be imposed on a holder of a renewed license other than those required by 10 CFR 54.37(b) would be processed by the DORL project manager in accordance with the requirements of 10 CFR 50.109 and existing backfit procedures. Notification of renewed license holders of applicable compliance ISG documents within the scope of 10 CFR 54.37(b) is coordinated with DORL before being issued. No ISG documents affecting holders of renewed licenses, other than those within the scope of 10 CFR 54.37(b), have been identified or issued to date.

In conclusion, we disagree with OIG's Finding E and Recommendations 7 and 8 that the NRC needs to establish a mechanism or methodology for conducting backfit analyses for ISG documents, and to designate and communicate accountability for performing the backfit analyses to all stakeholders. The backfit rule does not apply to license renewal applications under review and to changes that fall within the scope of 10 CFR 54.37(b). The ISG process clearly states that ISG documents not within the scope of 10 CFR 54.37(b) are subject to the requirements of the backfit rule. Procedures already exist within NRR to identify and control the imposition of backfits if such a change were identified in the future.

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Appendix F

OIG ANALYSIS OF AGENCY COMMENTS

On May 8, 2007, OIG issued its draft report to the Executive Director for Operations. OIG subsequently met with managers from the Division of License Renewal and the Office of the General Counsel to address specific issues and concerns needing further clarification and/or explanation. On May 24, 2007, OIG discussed its draft report with agency senior executives. Subsequent to that meeting, NRC provided informal comments on the draft report for OIG's consideration. On July 6, 2007, the Deputy Executive Director for Reactor Programs provided a formal response to this report in which the agency disagreed with OIG's finding regarding applicability of the backfit rule to license renewals applicants (see Appendix E). OIG's analysis of the agency's response is as follows:

The staff's position on backfit applicability to license renewal is addressed as it pertains to (1) holders of renewed licenses and (2) license renewal applicants. As discussed below, OIG agrees in part with the agency's position that under certain circumstances backfitting does not apply. However, as reflected in Figure 4, OIG disagrees with the agency's position regarding applicability of the backfit rule to license renewal applicants.

Figure 4
Application of Backfit to License Renewal

[redacted]	***Holders of Renewed Licenses*** NRC staff and OIG **agree** that the Backfit Rule <u>Does Not Apply</u>, per 10 CFR 54.37(b)*, to Newly Identified SSCs subject to aging management or time-limited aging analysis
	Holders of Renewed Licenses NRC staff and OIG **agree** that the Backfit Rule Backfit Rule <u>Does Apply</u> to New or Different Staff Positions affecting SSCs previously within the scope of license renewal

*10 CFR 54.37(b) has provided a specific exception from backfitting requirements for holders of renewed licenses, but only regarding "newly" identified SSCs subject to aging or time-limited aging analysis.

Figure 4 demonstrates the applicability of the Backfit Rule only as the Rule applies to staff positions regarding license renewal interpretations.

Holders of Renewed Licenses

OIG agrees with the staff's position that 10 CFR 50.109, "Backfitting," does not apply to license renewal (for holders of renewed licenses) with respect to new structures, systems or components (SSC) brought within the scope of the license renewal rule as required by 10 CFR 54.37(b). OIG also concurs with the staff's acknowledgement that the backfit rule does generally apply for SSCs that *were or should have been reviewed during the scope of license renewal review.* [emphasis added] However, the agency does not have a process to identify whether ISGs address new SSCs or those previously within the scope of license renewal reviews. As a result, there is no documented means to determine whether ISGs have met the provisions in 10 CFR 54.37(b) and thereby not subject to backfitting.

License Renewal Applicants

Again citing 10 CFR 54.37(b), the staff maintains that the backfitting rule does not apply to license renewal applicants. In support of this interpretation, the staff references a 1995 Commission SOC published with promulgation of the License Renewal Rule. The staff repeatedly told OIG that the 1995 SOC is the statement of the Commission's intent which sustains the staff's current position on the continued non-applicability of the backfit rule to license renewal applicants.

In OIG's opinion, the plain language of the backfit regulation states that the backfit rule is applicable to holders of an operating license, which by default includes applicants seeking a renewed license.[26] There is no exception in the backfit rule suspending applicability of the rule to subject matter related to a license renewal application

[26] 10 CFR 50.109(a)(1)(iii).

nor is there any provision in the License Renewal Rule indicating that backfitting does not apply to "applicants." Consequently, the sole regulatory basis for the staff's position that backfitting does not apply to applicants is the 1995 SOC.

OIG notes that the SOC does include some discussion of the Commission's rationale regarding backfitting and the license renewal regulation. This discussion included the following:

> "There are no licensees currently holding renewed nuclear power plant operating licenses who would be affected by this rule. No applications for license renewal have been docketed. It is also unlikely that any license renewal applications will be submitted before this rule becomes effective."[27]

OIG's assessment of the SOC is that the Commission based its 1995 position on backfitting, at least in part, on the practical reality that application of the backfit rule to new staff positions on license renewal made no sense at a time when there were no foreseeable license renewal applicants, much less current license renewal applicants or holders of renewed licenses. In OIG's opinion, it would have served no valid regulatory purpose to require backfitting at that time as there were no affected applicants, potential applicants, or holders of renewed licenses. However, the Commission's position in the SOC is 12 years old.

The Commission's membership and the underlying circumstances supporting the 1995 position have significantly changed. Specifically, at the time of this report, there are 48 holders of renewed licenses, eight current license renewal applicants, and the NRC expects approximately 23 new applicants through 2013. Within the current environment, applicants, potential applicants, and holders of renewed licenses all may be affected by new staff positions regarding license renewal. Therefore, the staff's continued reliance on the 1995 SOC regarding the application of

[27] Volume 60, *Federal Register*, at 22491, Page 40, 2nd Paragraph.

backfitting to license applicants is questionable. As a result, OIG is recommending that the current Commission affirm or modify the 1995 Statement of Considerations position regarding the applicability of the backfit rule to license renewal applicants.

Reference 6

FUSE
(FRIENDS UNITED FOR SUSTAINABLE ENERGY)
21 PERLMAN DRIVE
SPRING VALLEY, NY 10977
(845) 371-2100 TEL
(845) 371-3721 FAX

6/29/07

Dr. Pao-Tsin Kuo, PE
Director, Division of License Renewal
Mail Stop Q-11F1
Washington, DC 20555

Richard Barkley
Nuclear Regulatory Commission ("NRC")
475 Allendale Road
King of Prussia, PA 19406

Chairman's Office
Nuclear Regulatory Commission ("NRC")
Washington, DC 20555-0001

RE: Documents requested.

Dear Dr. Pao-Tsin Kuo:

I represent a large group of Stakeholders and am requesting the following documents from the NRC prior to the commencement of the 60 day intervener clock, as part of the relicensing review process.

1. All documents referred to and incorporated by reference in the relicense application must be made available by the Applicant, Entergy, for inspection in a public place in Westchester County, prior to the NRC starting the 60 day intervener clock.

2. A complete list of what systems and components are specifically within the scope of relicensing.

3. A complete list of all deviations and exemptions, extensions and dates for IP1, IP2 and IP3

4. A complete list of all the underground, inaccessible piping, how many feet, composition, and what is running through them.

5. A list of any and all criteria by which a new license can be denied.

6. A list of any and all criteria by which a new superceding license can be denied.

7. A cost analysis as to the actual cost of decommissioning IP1, IP2 and IP3 respectively, in light of the known and unknown leaks.

8. Electrical separation repair/mitigating documents and a walk down of the repairs.

9. Seek a mathematical/engineering determination if there is enough room in the spent fuel pools and dry cask field to store the nuclear waste that will be produced during the proposed license extension, with cooling towers.'

10. The financials for the past 6 years of the lobbying group, the NEI (Nuclear Energy Institute).

In addition we request ANY and ALL meetings, regarding the relicensing application, ASLAB or others, take place within Westchester County in proximity of the plant.

Thank you for your assistance.

Sincerely yours,

Susan Shapiro

FUSE
(FRIENDS UNITED FOR SUSTAINABLE ENERGY)
21 PERLMAN DRIVE
SPRING VALLEY, NY 10977
(845) 371-2100 TEL
(845) 371-3721 FAX

7/6/07

Entergy Northeast
Kathy McMullin
Manager of Communications
Indian Point Energy Center
450 Broadway, GSB
P.O. Box 249
Buchanan, New York 10511-0249

RE: Documents requested.

Dear Ms. McMullin:

I represent a large group of Stakeholders and am requesting the following documents prior to the commencement of the 60 day intervener clock, as part of the relicensing review process.

1. All documents referred to and incorporated by reference in the relicense application must be made available by the Applicant, Entergy, for inspection in a public place in Westchester County, prior to the NRC starting the 60 day intervener clock.

2. A complete list of all deviations and exemptions, extensions and dates for IP1, IP2 and IP3

3. A complete list and maps of all the underground, inaccessible piping, how many feet, composition, and what is running through them.

4. A cost analysis as to the actual cost of decommissioning IP1, IP2 and IP3 respectively, in light of the known and unknown leaks.

5. Electrical separation repair/mitigating documents and a walk down of the repairs.

6. Seek a mathematical/engineering determination if there is enough room in the spent fuel pools and dry cask field to store the nuclear waste that will be produced during the proposed license extension, with cooling towers.

7. Maps of any and all radioactive leaks, including but not limited to Strontium, Tritum and Cesium.

Thank you for your assistance.

Sincerely yours,

Susan Shapiro

9/4/07

Chairman's Office
Nuclear Regulatory Commission
Washington, DC 20555

Dr. Pao-Tsin Kuo, PE
Director, Division of License Renewal
Office of Nuclear Reactor Regulation

Cc: Senator Hillary Clinton
Senator Charles Schumer
Governor Eliot Spitzer
Attorney General Andrew Cuomo
Congressman Eliot Engel
Congresswoman Nita Lowey
Congressman John Hall
Congressman Maurice Hinchey

REQUEST EXTENSION to file Intervener Petitions and Requests of Hearings, until 60 days after Entergy makes the maps and leak studies due this fall, publicly available.

Dear Dr. Pao-Tsin Kuo:

Individually and jointly, Friends United for Sustainable Energy, USA. Inc. ("FUSE") and the undersigned parties ("Stakeholders") hereby make the following requests and demands:

On 6/29/07 FUSE requested the maps of the ongoing underground leaks of tritium, strontium and cesium radiation, under the nuclear plants Indian Point 1, 2 and 3 that both the NRC and Entergy have displayed at various public meetings.

To date, FUSE has not received said maps, and instead has only received the NRC's maps, which are unclear, and differ from the maps used by the NRC in meeting with Stakeholders.

Richard Barkley of the NRC has told FUSE that the maps are proprietary property of Entergy. They will not become available until after the NRC receives Entergy's leak report later this fall, which makes the October 1, 2007 deadline to file Intervener Petitions highly prejudicial in favor of the licensee at the expense of the Stakeholders and other citizens whose best interests are supposed to be served by this Federal regulatory body.

Clearly, these leak maps and the upcoming leak report contain vital information directly related to potential environmental impacts and infrastructure aging issues, and consequently Entergy's License Renewal Application ("LRA"). The maps are necessary for Stakeholders to file properly and fully documented Intervener contentions.

In fact, the NRC used these maps to discuss the leaks in public meetings with representatives of Riverkeeper, Clearwater and IPSEC. In addition these maps, minus the Cesium map, were displayed in the lobby of a public meeting, however copies were unavailable.

Therefore, the undersigned Stakeholders are requesting an extension to file Intervener Petitions and Request for Hearing until 60 days after Entergy and the NRC publish the leak Report and leak maps due this fall.

The relicensing calendar is set at the discretion of the NRC, and it would be inequitable for the NRC not to extend the Intervener filing deadline until after these vital documents, that pertain to public health and safety, are made publicly available.

NRC ISSUED EXTENSIONS FOR THE BACK-UP POWERED SIREN SYSTEM REQUIRED UNDER THE ENERGY POLICY ACT OF 2005:

Recently, the NRC has issued extensions to Entergy to install the required back-up powered siren system, that is required under the Energy Policy Act of 2005 to protect public health and safety.

The NRC issued a Confirmatory Order in January 2006 requiring the installation of back-up power for the siren system at Indian Point by Jan. 30, 2007. In January 2007, Entergy requested and received an extension but missed that deadline of April 15, 2007. The NRC merely fined Entergy $130,000 and extended the deadline to August 24, 2007, this new deadline has also been missed.

CONCLUSION:

THEREFORE, the undersigned Stakeholders request a reasonable filing extension, of Intervener Petitions and Requests for Hearings, until 60 days after Entergy's leak report and leak maps are made publicly available. This extension is in the best interest of the public health and safety. A denial of this extension request would result in interference with Stakeholders' rights to equal protection and would be clearly discriminatory,

Respectfully Submitted,

Susan Shapiro, Esq
Attorney for FUSE
Friends United for Sustainable Energy
21 Perlman Drive
Spring Valley, NY 10977

Thomas J. Abinanti
Westchester County Legislator
148 Martine Ave
White Plains NY

Connie L. Coker RN MSN CNM
Rockland County Legislator, District #17
New Hempstead Road
New City, NY

Michael Mariotte, Executive Director
Nuclear Information and Resource Service
6930 Carroll Avenue Suite 340
Takoma Park MD 20912

Indian Point Safe Energy Coalition (IPSEC)
PO BOX 134
Croton-on-Hudson, NY 10520

Michel Lee, Esq.
Chairman
Council on Intelligent Energy & Conservation Policy
P.O. Box 312
White Plains, New York 10601

Michael D. Diederich, Jr.
Attorney at Law
361 Route 210
Stony Point, NY 10980

Stephen Filler
Law Offices of Stephen Filler
303 South Broadway, Suite 222
Tarrytown, NY 10591

Alice Slater
Nuclear Age Peace Foundation, New York
446 E. 86 St.
New York, NY 10028

Rockland County Conservation Association, Inc
PO Box 213, Pomona, NY 10970

Arnold Gore
Consumers Health Freedom Coalition
720 Fort Washington Avenue
New York,NY 10040

George Potanovic, Jr.
SPACE President on behalf of
SPACE Board of Directors
Stony Point Action Committee for the Environment
PO Box 100
Stony Point, NY 10980

Barbara and Harold Greenhut
161 Doxbury Lane
Suffern, NY 10901

Keith Murdock
#4 Gilmore Dr.
Stony Point, NY 10980

Shaoli Che
#4 Gilmore Dr.
Stony Point, NY 10980

Stacey Hunter
46 Hastings Ave
Croton-on-Hudson, NY 10520

Dorice Madronero
4 Regis Ct.
Suffern, NY 10901

Liz Phillips
27 Grand Avenue
Nyack, NY 10960

Marian H. Rose, PhD
9 Old Corner Road
Bedford, NY 10506

David Wolff
12 Castle Hts.
Nyack, NY 10960

Janet Burnet
20 Spook Rock Road
Suffern, NY 10901

Samantha Lee
2168 Pondfield Court
Yorktown Heights, NY
10598

Beverly Stycos
701 South Mountain Road
New City, NY 10956

Ann Harbeson
5 Valley Trail
Croton on Hudson, NY 10520

Doris Metraux
17 Dogwood Lane
P.O.Box 317
Stony Point, NY 10980

Barbara Ehrentreu
126A Nethermont Avenue
North White Plains, NY 10603

Estelle & Joseph Burdige
17 Nansen Court
Spring Valley, NY 10977

Jeanne McDermott
One Lakeview Drive, Apt. LL2A
Peekskill, NY 10566

Jordan Kalfus
244 Pinesbridge Road
Millwood, NY 10546

Elizabeth C. Segal
33 Fairview Avenue
Tarrytown, NY 10591

Mark Rausher
298 Route 208
New Paltz, NY 12561

Tony LaMonte
284 City Island Avenue
Bronx, NY 10464

Tina Munson
270 River Road
Edgewater, NJ 07020

Bill Murawski
530 West 50th Street
New York, NY 10019

Betty Hedges
11 Ladentown Road
Pomona, New York 10970

Lee Sneden and Eloise Vega
1 Cobblestone Road
Airmont, NY 10952

Alexandra Soltow
7 Danbury Court
Suffern, NY 10901

Dean Gallea
28 Wildey Street
Tarrytown, NY 10591

Greg Miller
4 Woods Rd
Valley Cottage N.Y. 10989

Patricia Steinley-Davis
134 Lake Rd. E.
Congers, NY 10920

Margo Schepart
2651 Broadview Drive
Yorktown Heights, NY 10598

Nancy Kochanowicz Croton CIP
is 29 Van Wyck St.
Croton on Hudson, NY 10520

Sidney J. Goodman, P.E., M.S.M.E.
158 Grandview Lane
Mahwah, NJ 07430

Sarah Johnson
86 N. Midland Avenue
Nyack, NY 10960

Andrea Jacobson
30 Woodybrook Lane
Croton-on-Hudson, New York 10520

Michael Maguire
30 Woodybrook Lane
Croton-on-Hudson, New York 10520

Sophie Maguire
30 woodybrook lane
Croton-on-Hudson, New York 10520

Dylan Maguire
30 Woodybrook Lane
Croton-on-Hudson, New York 10520

Cari and Donald Gardner
44 Clarewood Drive
Hastings-on-Hudson, NY 10706

David Bedell
12 Ardsley Rd
Stamford, CT 06906

Judy W. Soffler
8 Termakay Drive
New City, NY 10956-6434

Greg Maher
44 Grand Street
Croton-on-Hudson, NY 10520

Andrew Fishkin
22 Lark Lane
Croton on Hudson, NY 10520

Ms. Alice B. Rasher
200 Diplomat Drive (#7N)
Mt. Kisco, N.Y.-10549-2035

Joyce Federiuk
28 Quaker Bridge Rd.
Croton on Hudson, NY 10520

Samantha Leonard
Box 1162
Vassar College
124 Raymond Ave
Poughkeepsie, NY 12604

Dan Doniger
53 W. 111th St., #4W
New York, NY 10026

Frances Cott
PO Box 182
Pomona, NY 10970

John L. Dacccardi
124 Rte 210
Stony Point, N.Y.10980

Joan & Arthur Wing
7 Van Alstine Avenue
Suffern, NY 10901

Marcia Kosstrin
43 Aquila Rd
Stamford, Ct 06902

Rosemary Waltzer
16 Sandusky Road
New City NY 10956

Henry Kassell
203 Rte 210
Stony Point, NY 10980

Lyn Borek
8 Andrew Drive
Chestnut Ridge, NY 10952-4603

Barbara Jacobs
76 Dimond Ave.
Cortlandt Manor, NY 10567

John Sullivan
735 Requa St.
Peekskill, New York 10566

Kamila and George Mejias
17 Park Place
Suffern, NY 10901

Joann Keenan
668 Riverside Drive
Apt. 1i
New York, NY 10031

Frank Collyer
Stony Point

Bettina Utz
345 East Mountain Road North
Cold Spring, NY 10516

Ellen Naney
26 Fairview Ave #5
High Falls NY 12440

Maureen Ritter
36 Campbell Road
Suffern, NY 10901

Jeff Wanshel
1 Spanish Cove Rd.
Larchmont, New York 10538

Sherwood Martinelli
53 Dykman St.
Peekskill, NY 10566

Jon Mann
23 Woodland Road
Bedford, NY 10506

John Deans
30 Pinetree Lane
Tappan, NY

Reference 2

United States General Accounting Office

GAO

Report to Congressional Requesters

May 2004

NUCLEAR REGULATION

NRC Needs to More Aggressively and Comprehensively Resolve Issues Related to the Davis-Besse Nuclear Power Plant's Shutdown

GAO

Accountability * Integrity * Reliability

GAO-04-415

GAO Accountability·Integrity·Reliability

Highlights

Highlights of GAO-04-415, a report to congressional requesters

Why GAO Did This Study

In March 2002, the most serious safety issue confronting the nation's commercial nuclear power industry since Three Mile Island in 1979 was identified at the Davis-Besse plant in Ohio. After the Nuclear Regulatory Commission (NRC) allowed Davis-Besse to delay shutting down to inspect its reactor vessel for cracked tubing, the plant found that leakage from these tubes had caused extensive corrosion on the vessel head—a vital barrier preventing a radioactive release. GAO determined (1) why NRC did not identify and prevent the corrosion, (2) whether the process NRC used in deciding to delay the shutdown was credible, and (3) whether NRC is taking sufficient action in the wake of the incident to prevent similar problems from developing at other plants.

What GAO Recommends

Because the nation's nuclear power plants are aging, GAO is recommending that NRC take more aggressive actions to mitigate the risk of serious safety problems occurring at Davis-Besse and other nuclear power plants.

NRC disagreed with two of the report's five recommendations—that it develop (1) additional means to better identify safety problems early and (2) guidance for making decisions whether to shut down a plant. GAO continues to believe these recommendations are appropriate and should be implemented.

www.gao.gov/cgi-bin/getrpt?GAO-04-415.

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 or wellsj@gao.gov.

May 2004

NUCLEAR REGULATION

NRC Needs to More Aggressively and Comprehensively Resolve Issues Related to the Davis-Besse Nuclear Power Plant's Shutdown

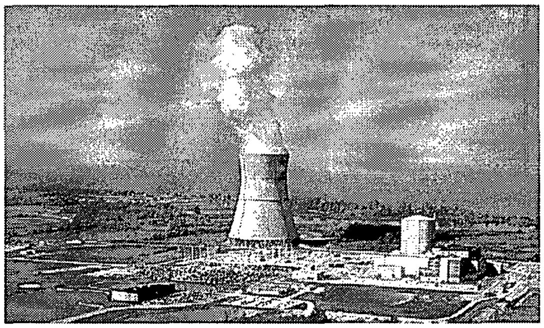
What GAO Found

NRC should have but did not identify or prevent the corrosion at Davis-Besse because its oversight did not generate accurate information on plant conditions. NRC inspectors were aware of indications of leaking tubes and corrosion; however, the inspectors did not recognize the indications' importance and did not fully communicate information about them. NRC also considered FirstEnergy—Davis-Besse's owner—a good performer, which resulted in fewer NRC inspections and questions about plant conditions. NRC was aware of the potential for cracked tubes and corrosion at plants like Davis-Besse but did not view them as an immediate concern. Thus, NRC did not modify its inspections to identify these conditions.

NRC's process for deciding to allow Davis-Besse to delay its shutdown lacks credibility. Because NRC had no guidance specifically for making a decision on whether a plant should shut down, it used guidance for deciding whether a plant should be allowed to modify its operating license. NRC did not always follow this guidance and generally did not document how it applied the guidance. The risk estimate NRC used to help decide whether the plant should shut down was also flawed and underestimated the amount of risk that Davis-Besse posed. Further, even though underestimated, the estimate still exceeded risk levels generally accepted by the agency.

NRC has taken several significant actions to help prevent reactor vessel corrosion from recurring at nuclear power plants. For example, NRC has required more extensive vessel examinations and augmented inspector training. However, NRC has not yet completed all of its planned actions and, more importantly, has no plans to address three systemic weaknesses underscored by the incident. Specifically, NRC has proposed no actions to help it better (1) identify early indications of deteriorating safety conditions at plants, (2) decide whether to shut down a plant, or (3) monitor actions taken in response to incidents at plants. Both NRC and GAO had previously identified problems in NRC programs that contributed to the Davis-Besse incident, yet these problems continue to persist.

The Davis-Besse Nuclear Power Plant in Oak Harbor, Ohio



Source: FirstEnergy.

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Abbreviations

NRC	Nuclear Regulatory Commission
PRA	Probabilistic risk assessment

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Accountability * Integrity * Reliability

United States General Accounting Office
Washington, D.C. 20548

May 17, 2004

Congressional Requesters

In 2002, the most serious safety issue confronting the nation's commercial nuclear power industry since the accident at Three Mile Island in 1979 was identified at the Davis-Besse nuclear power plant in northwestern Ohio. On March 7, 2002, during shutdown for inspection and refueling, the owner of the Davis-Besse plant—FirstEnergy Nuclear Operating Company—discovered a pineapple-sized cavity in the plant's carbon steel reactor vessel head. The reactor vessel head is an 18-foot-diameter, 6-inch-thick, 80-ton cap that is bolted to the reactor vessel. The vessel head is an integral part of the reactor coolant pressure boundary that serves as a vital barrier for protecting the environment from any release of radiation from the reactor core. In pressurized water reactors such as the one at Davis-Besse, the reactor vessel contains the nuclear fuel, as well as water with diluted boric acid that cools the fuel and helps control the nuclear reaction. At the Davis-Besse plant, vertical tubes had cracked that penetrate the reactor vessel head and that contain this water as well as drive mechanisms used to lower and raise the fuel, thus allowing leaked boric acid to corrode the reactor vessel head. The corrosion had extended through the vessel head to a thin stainless steel lining and had likely occurred over a period of several years. The lining, which is less than one-third of an inch thick and was not designed as a pressure barrier, was found to have a slight bulge with evidence of cracking. Had this lining given way, the water within the reactor vessel would have escaped, triggering a loss-of-coolant accident, which—if back-up safety systems had failed to operate—likely would have resulted in the melting of the radioactive core and a subsequent release of radioactive materials into the environment. In March 2004, after 2 years of increased NRC oversight and considerable repairs by FirstEnergy, NRC approved the restart of Davis-Besse's operations.

Under the Atomic Energy Act of 1954, as amended, and the Energy Reorganization Act of 1974, as amended, the Nuclear Regulatory Commission (NRC) and the operators of nuclear power plants share the responsibility for ensuring that nuclear reactors are operated safely. NRC is responsible for issuing regulations, licensing and inspecting plants, and requiring action, as necessary, to protect public health and safety; plant operators have the primary responsibility for safely operating the plants in accordance with their licenses. NRC has the authority to order plant operators to take actions, up to and including shutting down a plant, if licensing conditions are not being met and the plant poses an undue risk to public health and safety. In carrying out its responsibilities, NRC relies on, among other things, on-site NRC resident inspectors to assess plant conditions and quality assurance programs, such as those for maintenance and operations, that operators establish to ensure safety at the plant.

Before the discovery of the cavity in the Davis-Besse reactor vessel head, NRC had requested that operators of Davis-Besse and other similar pressurized water reactors (1) thoroughly inspect the vertical tubing on their reactor vessel heads by December 31, 2001, for possible cracking, or (2) justify why their tubing and reactor vessel heads were sufficiently safe without being inspected. This request was a reaction to cracked vertical tubing found on a pressurized water reactor vessel head at another plant. Such thorough inspections require that the reactor be shut down. FirstEnergy, believing that its reactor vessel head was safe, asked NRC if its shutdown could be delayed until the end of March 2002 to coincide with an already scheduled shutdown for refueling—during which time it would conduct the requested inspection. FirstEnergy provided evidence supporting its assertion that the reactor could continue operating safely. After considerable discussion, and after NRC developed a risk assessment estimate for deciding that Davis-Besse would not pose an unacceptable level of risk, NRC and FirstEnergy compromised, and FirstEnergy agreed to shut down the reactor in mid-February 2002 for inspection. Soon after Davis-Besse was shut down, the cracked tubes and the significant reactor vessel head corrosion were discovered.

You asked us to determine (1) why NRC did not identify and prevent the vessel head corrosion at Davis-Besse, (2) whether the process NRC used when deciding to allow FirstEnergy to delay its shutdown was credible, and (3) whether NRC is taking sufficient action in the wake of the Davis-Besse incident to prevent similar problems from developing in the future at Davis-Besse and other nuclear power plants. As agreed with your offices, our review focused on NRC's role in the events leading up to Davis-Besse's shutdown, NRC's response to the problems discovered, and NRC's management controls over programs and processes that may have contributed to the Davis-Besse incident. We did not evaluate the role of FirstEnergy because, at the time of our review, NRC's Office of Investigations and the Department of Justice were conducting separate inquiries into the potential liability of FirstEnergy concerning its knowledge of conditions at Davis-Besse, including the condition of the reactor vessel head. We also did not review NRC's March 2004 decision to allow the plant to restart.

Scope and Methodology

To determine why NRC did not identify and prevent the vessel head corrosion at the Davis-Besse nuclear power plant, we reviewed NRC's lessons-learned task force report;[1] FirstEnergy's root cause analysis reports;[2] NRC's Office of the Inspector General reports on Davis-Besse;[3] NRC's augmented inspection team report;[4] and NRC's inspection reports and licensee assessments from 1998 through 2001. We also reviewed NRC generic communications issued on boric acid corrosion and on nozzle cracking. In addition, we interviewed NRC regional officials who were involved in overseeing Davis-Besse at the time corrosion was occurring, and when the reactor vessel head cavity was found, to learn what information they had, their knowledge of plant activities, and how they communicated information to headquarters. We also held discussions with the resident inspector who was at Davis-Besse at the time that corrosion was occurring to determine what information he had and how this information was communicated to the regional office. Further, we met with FirstEnergy and NRC officials at Davis-Besse and walked through the facility, including the containment building, to understand the nature and extent of NRC's oversight of licensees. Additionally, we met with NRC headquarters officials to discuss the oversight process as it related to Davis-Besse, and the extent of their knowledge of conditions at Davis-Besse. We also met with county officials from Ottawa County, Ohio, to discuss their views on NRC and Davis-Besse plant safety. Further, we met with representatives from a variety of public interest groups to obtain their thoughts on NRC's oversight and the agency's proposed changes in the wake of Davis-Besse.

[1]NRC, *Degradation of Davis-Besse Nuclear Power Station Reactor Pressure Vessel Head Lessons-Learned Report* (Washington, D.C.; Sept. 30, 2002).

[2]FirstEnergy, Davis-Besse Nuclear Power Station, *Root Cause Analysis Report: Significant Degradation of the Reactor Pressure Vessel Head, CR 2002-089* (Oak Harbor, Ohio; Aug. 27, 2002) and *Root Cause Analysis Report: Failure to Identify Significant Degradation of the Reactor Pressure Vessel Head, CR-02-0685, 02-0846, 02-0891, 02-1053, 02-1128, 02-1583, 02-1850, 02-2584, and 02-2585* (Oak Harbor, Ohio; Aug. 13, 2002).

[3]NRC, Office of the Inspector General, *NRC's Regulation of Davis-Besse Regarding Damage to the Reactor Vessel Head* (Washington, D.C.; Dec. 30, 2002) and *NRC's Oversight of Davis-Besse Boric Acid Leakage and Corrosion during the April 2000 Refueling Outage* (Washington, D.C.: Oct. 17, 2003).

[4]NRC, *Davis-Besse Nuclear Power Station NRC Augmented Inspection Team—Degradation of the Reactor Pressure Vessel Head* (Washington, D.C.; May 3, 2002).

To determine whether the process NRC used was credible when deciding to allow Davis-Besse to delay its shutdown, we evaluated NRC guidelines for reviewing licensee requests for temporary and permanent license changes, or amendments to their licenses. We also reviewed NRC guidance for making and documenting agency decisions, such as those on whether to accept licensee responses to generic communications, as well as NRC's policies and procedures for taking enforcement action. We supplemented these reviews with an analysis of internal NRC correspondence related to the decision-making process, including e-mail correspondence, notes, and briefing slides. We also reviewed NRC's request for additional information to FirstEnergy following the issuance of NRC's generic bulletin for conducting reactor vessel head and nozzle inspections, as well as responses provided by FirstEnergy. In addition, we reviewed the draft shutdown order that NRC prepared before accepting FirstEnergy's proposal to conduct its inspection in mid-February 2002. We reviewed these documents to determine whether the basis for NRC's decision was clearly laid out, persuasive, and defensible to a party outside of NRC.

As part of our analysis for determining whether NRC's process was credible, we also obtained and reviewed NRC's probabilistic risk assessment (PRA) calculations that it developed to guide its decision making. To conduct this analysis, we relied on the advice of consultants who, collectively, have an extensive background in nuclear engineering, PRA, and metallurgy. These consultants included Dr. John C. Lee, Professor and Chair, Nuclear Engineering and Radiological Sciences at the University of Michigan's College of Engineering; Dr. Thomas H. Pigford, Professor Emeritus, at the University of California-Berkeley's College of Engineering; and Dr. Gary S. Was, Associate Dean for Research in the College of Engineering, and Professor, Nuclear Engineering and Radiological Sciences at the University of Michigan's College of Engineering. These consultants reviewed internal NRC correspondence relating to NRC's PRA estimate, NRC's calculations, and the basis for these calculations. These consultants also discussed the basis for NRC's estimates with NRC officials and outside contractors who provided information to NRC as it developed its estimates. These consultants were selected on the basis of recommendations made by other nuclear engineering experts, their résumés, their collective experience, lack of a conflict of interest, and previous experience with assessing incidents at nuclear power plants such as Three Mile Island.

To determine whether NRC is taking sufficient action in the wake of the Davis-Besse incident to prevent similar problems from developing in the future, we reviewed NRC's lessons-learned task force recommendations, NRC's analysis of the underlying causes for failing to identify the corrosion of the reactor vessel head, and NRC's action plan developed in response to the task force recommendations. We also reviewed other NRC lessons-learned task force reports and their recommendations, our prior reports to identify issues related to those at Davis-Besse, and NRC's Office of the Inspector General reports. We met with NRC officials responsible for implementing task force recommendations to obtain a clear understanding of the actions they were taking and the status of their efforts, and discussed NRC's recommendations with NRC regional officials, on-site inspectors, and representatives from public interest groups. We conducted our review from November 2002 through May 2004 in accordance with generally accepted government auditing standards.

Results in Brief

NRC should have but did not identify or prevent the vessel head corrosion at Davis-Besse because both its inspections at the plant and its assessments of the operator's performance yielded inaccurate and incomplete information on plant safety conditions. With respect to inspections, NRC resident inspectors had information revealing potential problems, such as boric acid deposits on the vessel head and air monitors clogged with boric acid deposits, but this information did not raise alarms about the plant's safety. NRC inspectors did not know that these indications could signal a potentially significant problem and therefore did not fully communicate their observations to other NRC staff, some of whom might have recognized the significance of the problem. However, even if these staff had been informed, according to NRC officials, the agency would have taken action only if these indications were considered significant safety concerns. Furthermore, NRC's assessments of Davis-Besse, which include inspection results as well as other data, did not provide complete and accurate information on FirstEnergy's performance. For example, NRC consistently assessed Davis-Besse's operator as a "good performer" during those years when the corrosion was likely occurring, and the operator was not correctly identifying the source of boric acid deposits. NRC had been aware for several years that corrosion and cracking were issues that could possibly affect safety, but did not view them as immediate safety concerns and therefore had not fully incorporated them into its oversight process.

NRC's process for deciding whether Davis-Besse could delay its shutdown to inspect for nozzle cracking lacks credibility because the guidance NRC used was not intended for making such a decision and the basis for the decision was not fully documented. In the absence of written guidance specifically intended to direct the decision-making process for a shutdown, NRC used guidance designed for considering operator requests for license amendments. This guidance describes safety factors that NRC should consider in deciding whether to approve a license amendment, as well as a process for considering the relative risk the amendment could pose. However, the guidance does not specify how NRC should use the safety factors, and we could not determine if NRC appropriately followed this guidance because it did not clearly document the basis for its decision. For example, NRC initially decided that several safety factors were not met and considered issuing a shutdown order. Regardless, the agency allowed FirstEnergy to delay its shutdown, even though it is not clear whether—and if so, how—the safety factors were subsequently met. Further, NRC did not provide a rationale for its decision for more than a year. NRC also did not follow other aspects of its guidance. In the absence of specific guidance, and with little documentation of the decision-making process, we could not judge whether the agency's decision was reasonable. Our consultants identified substantial problems with how NRC developed and used its risk estimate when making the decision. For example, NRC did not perform an analysis of the uncertainty associated with the risk estimate; if it had, our consultants believe the uncertainty would have been so large as to render NRC's risk estimate of questionable value. Further, the risk estimate indicated that the likelihood of an accident occurring at Davis-Besse was greater than the level of risk generally accepted as being reasonable by NRC.

Responding to the Davis-Besse incident, NRC has taken several significant actions to help prevent boric acid from corroding reactor vessel heads at nuclear power plants. NRC issued requirements that licensees more extensively examine their reactor vessel heads, revised NRC inspection guidance used to identify and resolve licensee problems before they affect operations, augmented training to keep its inspectors better informed about boric acid and cracking issues, and revised guidance to better ensure that licensees implement commitments to change their operations. However, NRC has not yet implemented more than half of its planned actions, and resource constraints could affect the agency's ability to fully and effectively implement the actions. More importantly, NRC is not addressing three systemic problems underscored by the Davis-Besse incident. First, its process for assessing safety at nuclear power plants is not adequate for detecting early indications of deteriorating safety. In this respect, the process does not effectively identify changes in the operator's performance or approach to safety before a more serious safety problem can develop. Second, NRC's decision-making guidance does not specifically address shutdown decisions or explain how different safety considerations, such as quantitative estimates of risk, should be weighed. Third, NRC does not have adequate management controls for systematically tracking actions that it has taken in response to incidents at plants to determine if the actions were sufficient to resolve underlying problems and thereby prevent future incidents. Analyses of earlier incidents at other plants identified several issues, such as inadequate communication, that contributed to the Davis-Besse incident. Such management controls may have helped to resolve these issues before the Davis-Besse incident occurred. While NRC is monitoring how it implements actions taken as a result of the Davis-Besse incident, the agency has not yet committed to a process for assessing the effectiveness of actions taken.

Given NRC's actions in response to Davis-Besse, severe vessel head corrosion is unlikely to occur at a plant any time soon. However, in part because of unresolved systemic problems, another incident unrelated to vessel head corrosion could occur in the future. As a result, we are recommending that NRC take more aggressive and specific actions in several areas, such as revising how it assesses plant performance, establishing a more specific methodology for deciding to shut down a plant, and establishing management controls for monitoring and assessing the effectiveness of changes made in response to task force findings.

In commenting on a draft of this report, NRC generally addressed only those findings and recommendations with which it disagreed. While commenting that it agreed with many of our findings, the agency said that the report overall does not appropriately characterize or provide a balanced perspective on NRC's actions surrounding the discovery of the reactor vessel head condition at Davis-Besse or its efforts to incorporate the lessons learned from that experience into its processes. More specifically, NRC stated that the report does not acknowledge that NRC must rely heavily on its licensees to provide complete and accurate information. NRC also expressed concern about the report's characterization of its use of risk estimates. We believe that the report fairly and accurately describes NRC's actions regarding the Davis-Besse incident. Nonetheless, we expanded our discussion of NRC's roles and responsibilities to point out that licensees are required to provide NRC with complete and accurate information.

NRC disagreed with our recommendations to develop (1) specific guidance and a well-defined process for deciding when to shut down a plant and (2) a methodology to assess early indications of deteriorating safety at nuclear power plants. NRC stated that it has sufficient guidance to make plant shutdown decisions. NRC also stated that, as regulators, the agency is not charged with managing licensees' facilities and that direct involvement with those aspects of licensees' operations that could provide it with information on early indications of deteriorating safety crosses over to a management function. We continue to believe that NRC should develop specific guidance and a well-defined process to decide when to shut down a plant. In absence of such guidance for making the Davis-Besse shutdown decision, NRC used its guidance for considering operators' requests for amendments to their licenses. This guidance describes safety factors that NRC should consider in deciding whether to approve license changes, as well as a process for considering the relative risk the amendment would pose. This guidance does not specify how NRC should use the safety factors. We also continue to believe that NRC should develop a methodology to assess aspects of licensees' operations as a means to have an early warning of developing safety problems. In implementing this recommendation, we envision that NRC would be analyzing data for changes in operators' performance or approach to safety, not prescribing how the plants are managed.

Background

NRC's Role and Responsibilities

NRC, as an independent federal agency, regulates the commercial uses of nuclear material to ensure adequate protection of public health and safety and the environment. NRC is headed by a five-member commission appointed by the President and confirmed by the Senate; one commissioner is appointed as chairman.[5] NRC has about 2,900 employees who work in its headquarters office in Rockville, Maryland, and its four regional offices. NRC is financed primarily by fees that it imposes on commercial users of the nuclear material that it regulates. For fiscal year 2004, NRC's appropriated budget of $626 million includes about $546 million financed by these fees.

NRC regulates the nation's commercial nuclear power plants by establishing requirements for plant owners and operators to follow in the design, construction, and operation of the nuclear reactors. NRC also

[5]Two commissioner positions are currently vacant.

licenses the reactors and individuals who operate them. Currently, 104 commercial nuclear reactors at 65 locations are licensed to operate.[6] Many of these reactors have been in service since the early to mid-1970s. NRC initially licensed the reactors to operate for 40 years, but as these licenses approach their expiration dates, NRC has been granting 20-year extensions.

To ensure the reactors are operated within their licensing requirements and technical specifications, NRC oversees them by both inspecting activities at the plants and assessing plant performance.[7] NRC's inspections consist of both routine, or baseline, inspections and supplemental inspections to assess particular licensee programs or issues that arise at a power plant. Inspections may also occur in response to a specific operational problem or event that has occurred at a plant. NRC maintains inspectors at every operating nuclear power plant in the United States and supplements the inspections conducted by these resident inspectors with inspections conducted by staff from its regional offices and from headquarters. Generally, inspectors verify that the plant's operator qualifications and operations, engineering, maintenance, fuel handling, emergency preparedness, and environmental and radiation protection programs are adequate and comply with NRC safety requirements. NRC also oversees licensees by requesting information on their activities. NRC requires that information provided by licensees be complete and accurate and, according to NRC officials, this is an important aspect of the agency's oversight.[8] While we have added information to this report on the requirement that licensees provide NRC with complete and accurate information, we believe that NRC's oversight program should not place undue reliance on this requirement.

Nuclear power plants have many physical structures, systems, and components, and licensees have numerous activities under way, 24-hours a

[6]These licensed reactors include Browns Ferry Unit 1—one of three reactors owned by the Tennessee Valley Authority in Alabama—which was shut down in 1985. The Tennessee Valley Authority plans to restart the reactor in 2007, which will require NRC approval.

[7]NRC's oversight program has changed significantly since the beginning of 1998. The third and most recent change occurred in mid-2000, when the agency adopted its Reactor Oversight Process. Under this process, NRC continues to rely on inspection results to assess licensee performance. However, it supplements this information with other indicators of self-reported licensee performance, such as how frequently unscheduled shutdowns occur.

[8]10 C.F.R. § 50.9 requires that information provided by licensees be complete and accurate in all material respects.

day, to ensure the plants operate safely. Programs to ensure quality assurance and safe operations include monitoring, maintenance, and inspection. To carry out these programs, licensees typically prepare several thousand reports per year describing conditions at the plant that need to be addressed to ensure continued safe operations. Because of the large number of activities and physical structures, systems, and components, NRC focuses its inspections on those activities and pieces of equipment or systems that are considered to be most significant for protecting public health and safety. NRC terms this a "risk-informed" approach for regulating nuclear power plants. Under this risk-informed approach, some systems and activities that NRC considers to have relatively less safety significance receive little NRC oversight. NRC has adopted a risk-informed approach because it believes it can focus its regulatory resources on those areas of the plant that the agency considers to be most important to safety. In addition, it was able to adopt this approach because, according to NRC, safety performance at nuclear power plants has improved as a result of more than 25 years of operating experience.

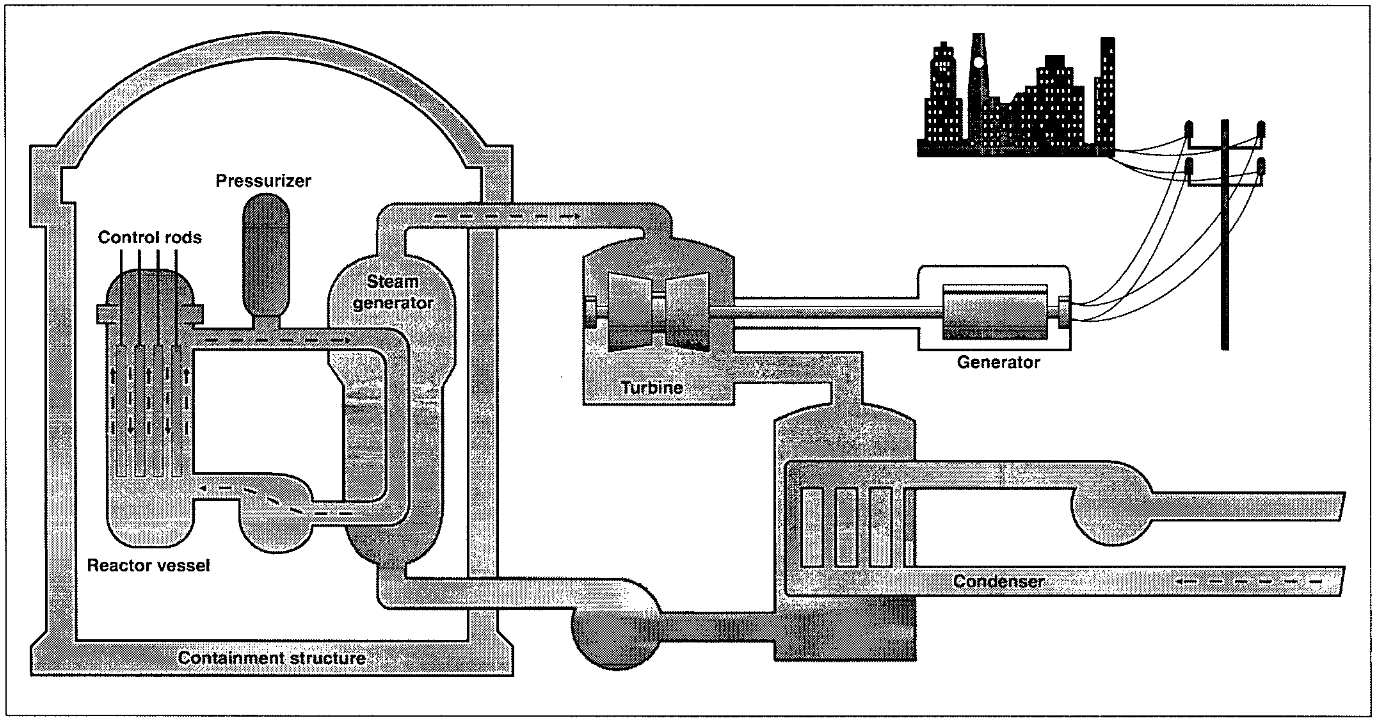
To decide whether inspection findings are minor or major, NRC uses a process it began in 2000 to determine the extent to which violations compromise plant safety. Under this process, NRC characterizes the significance of its inspection findings by using a significance determination process to evaluate how an inspection finding impacts the margin of safety at a power plant. NRC has a range of enforcement actions it can take, depending on how much the safety of the plant had been compromised. For findings that have low safety significance, NRC can choose to take no formal enforcement action. In these instances, nonetheless, licensees remain responsible for addressing the identified problems. For more serious findings, NRC may take more formal action, such as issuing enforcement orders. Orders can be used to modify, suspend, or even revoke an operating license. NRC has issued one enforcement order to shut down an operating power plant in its 28-year history—in 1987, after NRC discovered control room personnel sleeping while on duty at the Peach Bottom nuclear power plant in Pennsylvania. In addition to enforcement orders, NRC can issue civil penalties of up to $120,000 per violation per day. Although NRC does not normally use civil penalties for violations associated with its Reactor Oversight Process, NRC will consider using them for issues that are willful, have the potential for impacting the agency's regulatory process, or have actual public health and safety consequences. In fiscal year 2003, NRC proposed imposing civil penalties totaling $120,000 against two power plant licensees for the failure to provide complete and accurate information to the agency.

NRC uses generic communications—such as bulletins, generic letters, and information notices—to provide information to and request information from the nuclear industry at large or specific groups of licensees. Bulletins and generic letters both usually request information from licensees regarding their compliance with specific regulations. They do not require licensees to take any specific actions, but do require licensees to provide responses to the information requests. In general, NRC uses bulletins, as opposed to generic letters, to address significant issues of greater urgency. NRC uses information notices to transmit significant recently identified information about safety, safeguards, or environmental issues. Licensees are expected to review the information to determine whether it is applicable to their operations and consider action to avoid similar problems.

Operation of Pressurized Water Nuclear Power Plants and Events Leading to the March 2002 Discovery of Serious Corrosion

The Davis-Besse Nuclear Power Station, owned and operated by FirstEnergy Nuclear Operating Company, is an 882-megawatt electric pressurized water reactor located on Lake Erie in Oak Harbor, Ohio, about 20 miles east of Toledo. The power plant is under NRC's Region III oversight, which is located in Lisle, Illinois. Like other pressurized water reactors, Davis-Besse is designed with multiple barriers between the radioactive heat-producing core and the outside environment—a design concept called "defense-in-depth." Three main design components provide defense-in-depth. First, the reactor core is designed to retain radioactive material within the uranium oxide fuel, which is also covered with a layer of metal tubing. Second, a 6-inch-thick carbon steel vessel, lined with three-sixteenth-inch-thick stainless steel, surrounds the reactor core. Third, a steel containment structure, surrounded by a thick reinforced concrete building, encloses the reactor vessel and other systems and components important for maintaining safety. The containment structure and concrete building are intended to help not only prevent a release of radioactivity to the environment, but also shield the reactor from external hazards like tornados and missiles. The reactor vessel, in addition to housing the reactor core, contains highly pressurized water to cool the radioactive heat-producing core and transfer heat to a steam generator. Consequently, the vessel is referred to as the reactor pressure vessel. From the vessel, hot pressurized water is piped to the steam generator, where a separate supply of water is turned to steam to drive turbines that generate electricity. (See fig. 1.)

Figure 1: Major Components of a Pressurized Water Reactor



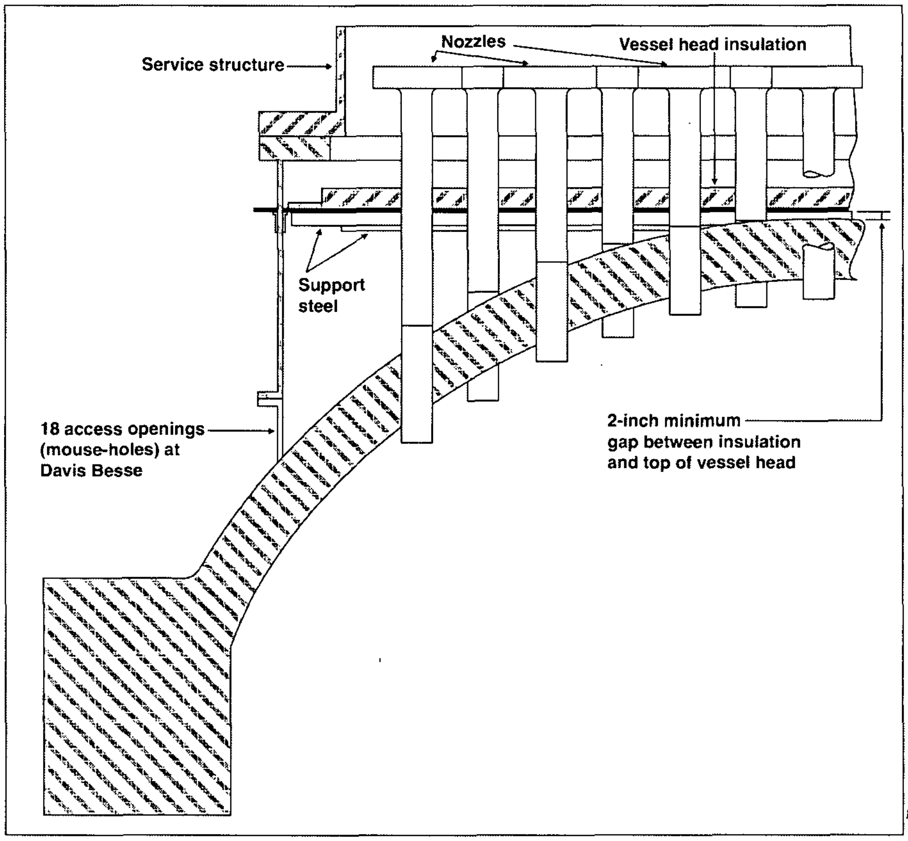
Source: NRC.

The top portion of the Davis-Besse reactor pressure vessel consisted of an 18-foot-diameter vessel head that was bolted to the lower portion of the pressure vessel. At Davis-Besse, 69 vertical tubes penetrated and were welded to the vessel head. These tubes, called vessel head penetration nozzles, contained control rods that, when raised or lowered, were used to moderate or shut down the nuclear reaction in the reactor.[9] Because control rods attach to control rod drive mechanisms, these types of nozzles are referred to as control rod drive mechanism nozzles. A platform, known as the service structure, sat above the reactor vessel head and the control rod drive mechanism nozzles. Inside the service structure and above the pressure vessel head was a layer of insulation to help contain the heat emanating from the reactor. The sides of the lower portion of the service

[9]While Davis-Besse had 69 nozzles, 7 were spare and 1 was used for head vent piping.

structure were perforated with 18 5- by 7-inch rectangular openings, termed “mouse-holes,” that were used for vessel head inspections. In pressurized water reactors such as Davis-Besse, the reactor vessel, the vessel head, the nozzles, and other equipment used to ensure a continuous supply of pressurized water in the reactor vessel are collectively referred to as the reactor coolant pressure boundary. (See fig. 2.)

Figure 2: Major Components of the Davis-Besse Reactor Vessel Head and Pressure Boundary



Source: FirstEnergy.

To better control the nuclear reaction at nuclear power plants, boron in the form of boric acid crystals is dissolved in the cooling water contained within the reactor vessel and pressure boundary. Boric acid, under certain conditions, can cause corrosion of carbon steel. For about 3 decades, NRC and the nuclear power industry have known that boric acid had the potential to corrode reactor components. In general, if leakage occurs from the reactor coolant system, the escaping coolant will flash to steam and leave behind a concentration of impurities, including noncorrosive dry boric acid crystals. However, under certain conditions, the coolant will not flash to steam, and the boric acid will remain in a liquid state where it can cause extensive and rapid degradation of any carbon steel components it contacts. Such extensive degradation, in both domestic and foreign pressurized water reactor plants, has been well documented and led NRC to issue a generic letter in 1988 requesting information from pressurized water reactor licensees to ensure they had implemented programs to control boric acid corrosion. NRC was primarily concerned that boric acid corrosion could compromise the reactor coolant pressure boundary. This concern also led NRC to develop a procedure for inspecting licensees' boric acid corrosion control programs and led the Electric Power Research Institute to issue guidance on boric acid corrosion control.[10]

NRC and the nuclear power industry have also known that nozzles made of alloy 600,[11] used in several areas within nuclear power plants, were prone to cracking. Cracking had become an increasingly topical issue as the nuclear power plant fleet has aged. In 1986, operators at domestic and foreign pressurized water reactors began reporting leaks in various types of alloy 600 nozzles. In 1989, after leakage was detected at a domestic plant, NRC identified the cause of the leakage as cracking due to primary water stress corrosion.[12] However, NRC concluded that the cracking was not an immediate safety concern for a few reasons. For example, the cracks had a low growth rate, were in a material with an extremely high flaw tolerance and, accordingly, were unlikely to spread. Also, the cracks were axial—that is, they ran the length of the nozzle rather than its circumference. NRC and

[10]The Electric Power Research Institute is a nonprofit energy research consortium whose members include utilities. It provides science and technology-based solutions to members through its scientific research, technology development, and product implementation program.

[11]Alloy 600 is an alloy of nickel, chromium, iron, and minor amounts of other elements. The alloy is highly resistant to general corrosion but can be susceptible to cracking at high temperatures.

[12]Primary water stress corrosion cracking refers to cracking under stress and in primary coolant water. The primary water coolant system is that portion of a nuclear power plant's coolant system that cools the reactor core in the reactor pressure vessel and deposits heat to the steam generator.

the nuclear power industry were more concerned that circumferential cracks could result in broken or snapped nozzles. NRC did, however, issue a generic information notice in 1990 to inform the industry of alloy 600 cracking. Through the early 1990s, NRC, the Nuclear Energy Institute,[13] and others continued to monitor alloy 600 cracking. In 1997, continued concern over cracking led NRC to issue a generic letter to pressurized water reactor licensees requesting information on their plans to monitor and manage cracking in vessel head penetration nozzles as well as to examine these nozzles.

In the spring of 2001, licensee inspections led to the discovery of large circumferential cracking in several vessel head penetration nozzles at the Oconee Nuclear Station, in South Carolina. As a result of the discovery, the nuclear power industry and NRC categorized the 69 operating pressurized water reactors in the United States into different groups on the basis of (1) whether cracking had already been found and (2) how similar they were to Oconee in terms of the amount of time and the temperature at which the reactors had operated. The industry had developed information indicating that greater operating time and temperature were related to cracking. In total, five reactors at three locations were categorized as having already identified cracking, while seven reactors at five locations were categorized as being highly susceptible, given their similarity to Oconee.[14]

In August 2001, NRC issued a bulletin requesting that licensees of these reactors provide, within 30 days, information on their plans for conducting nozzle inspections before December 31, 2001.[15] In lieu of this information, NRC stated that licensees could provide the agency with a reasoned basis for their conclusions that their reactor vessel pressure boundaries would continue to meet regulatory requirements for ensuring the structural integrity of the reactor coolant pressure boundary until the licensees

[13]The Nuclear Energy Institute comprises companies that operate commercial power plants and supports the commercial nuclear industry; and universities, research laboratories, and labor unions affiliated with the nuclear industry. Among other things, it provides a forum to resolve technical and business issues and offers information to its members and policymakers on nuclear issues.

[14]Reactors that were categorized as having already identified cracking or were highly susceptible included Arkansas Nuclear reactor unit 1; D.C. Cook reactor unit 2; Davis-Besse; North Anna reactor units 1 and 2; Oconee reactor units 1, 2 and 3; Robinson reactor unit 2; Surry reactor units 1 and 2; and Three Mile Island reactor unit 1.

[15]NRC, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles" (Bulletin 2001-01, Aug. 8, 2001).

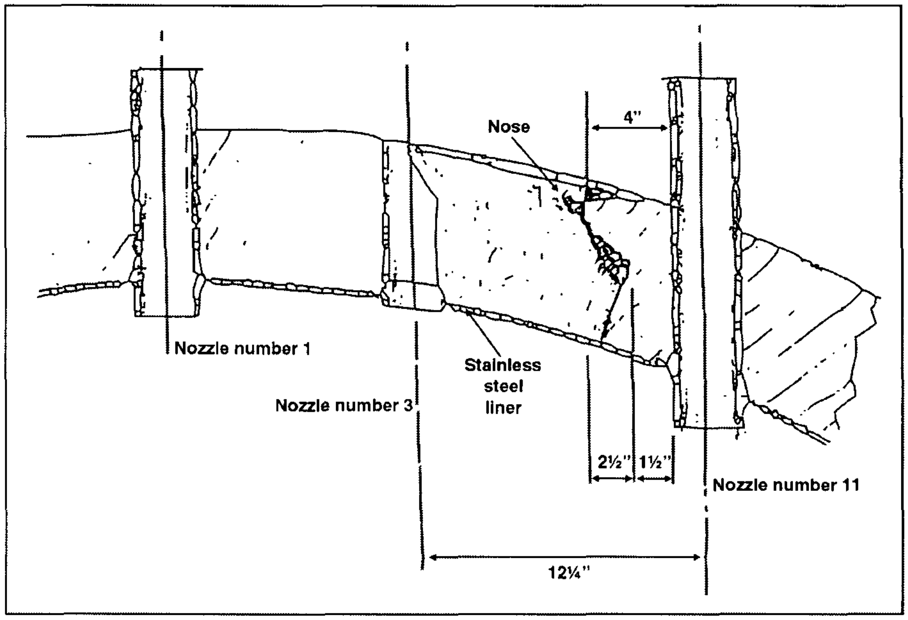
conducted their inspections. NRC used a bulletin, as opposed to a generic letter, to request this information because cracking was considered a significant and urgent issue. All of the licensees of the highly susceptible reactors, except Davis-Besse and D.C. Cook reactor unit 2, provided NRC with plans for conducting inspections by December 31, 2001.[16]

In September 2001, FirstEnergy proposed conducting the requested inspection in April 2002, following its planned March 31, 2002, shutdown to replace fuel. In making this proposal, FirstEnergy contended that the reactor coolant pressure boundary at Davis-Besse met and would continue to meet regulatory requirements until its inspection. NRC and FirstEnergy exchanged information throughout the fall of 2001 regarding when FirstEnergy would conduct the inspection at Davis-Besse. NRC drafted an enforcement order that would have shut down Davis-Besse by December 2001 for the requested inspection in the event that FirstEnergy could not provide an adequate justification for safe operation beyond December 31, 2001, but ultimately compromised on a mid-February 2002 shutdown date. NRC, in deciding when FirstEnergy had to shut down Davis-Besse for the inspection, used a risk-informed decision-making process, including probabilistic risk assessment (PRA), to conclude that the risk that Davis-Besse would have an accident in the interim was relatively low. PRA is an analytical tool for estimating the probability that a potential accident might occur by examining how physical structures, systems, and components, along with employees, work together to ensure plant safety.

Following the mid-February 2002 shutdown and in the course of its inspection in March 2002, FirstEnergy removed about 900 pounds of boric acid crystals and powder from the reactor vessel head, and subsequently discovered three cracked nozzles. The number of nozzles that had cracked, as well as the extent of cracking, was consistent with analyses that NRC staff had conducted prior to the shutdown. However, in examining the extent of cracking, FirstEnergy also discovered that corrosion had caused a pineapple-sized cavity in the reactor vessel head. (See figs. 3 and 4.)

[16]The licensee for D.C. Cook reactor unit 2 proposed to shut down in mid-January 2002 for its inspection. NRC agreed to the delay after crediting D.C. Cook for having been shut down for about a month during the fall of 2001, thus reducing the reactor's operating time.

Figure 3: Diagram of the Cavity in Davis-Besse's Reactor Vessel Head



Source: FirstEnergy.

Figure 4: The Cavity in Davis-Besse's Reactor Vessel Head after Discovery

Source: FirstEnergy.

After this discovery, NRC directed FirstEnergy to, among other things, determine the root cause of the corrosion and obtain NRC approval before restarting Davis-Besse. NRC also dispatched an augmented inspection team consisting of NRC resident, regional, and headquarters officials.[17] The inspection team concluded that the cavity was caused by boric acid corrosion from leaks through the control rod drive mechanism nozzles in the reactor vessel head. Primary water stress corrosion cracking of the nozzles caused through-wall cracks, which led to the leakage and eventual corrosion of the vessel head. NRC's inspection team also concluded, among other things, that this corrosion had gone undetected for an extended period of time—at least 4 years—and significantly compromised the plant's

[17]NRC forms such inspection teams to ensure that the agency investigates significant operational events in a timely, objective, systematic, and technically sound manner, and identifies and documents the causes of such events.

safety margins. As of May 2004, NRC had not yet completed other analyses, including how long Davis-Besse could have continued to operate with the corrosion it had experienced before a vessel head loss-of-coolant accident would have occurred.[18] However, on May 4, 2004, NRC released preliminary results of its analysis of the vessel head and cracked cladding. Based on its analysis of conditions that existed on February 16, 2002, NRC estimated that Davis-Besse could have operated for another 2 to 13 months without the vessel head failing. However, the agency cautioned that this estimate was based on several uncertainties associated with the complex network of cracks on the cladding and the lack of knowledge about corrosion and cracking rates. NRC plans to use this data in preparing its preliminary analysis of how, and the likelihood that, the events at Davis-Besse could have led to core damage. NRC plans to complete this preliminary analysis in the summer of 2004.

NRC also established a special oversight panel to (1) coordinate NRC's efforts to assess FirstEnergy's performance problems that resulted in the corrosion damage, (2) monitor Davis-Besse's corrective actions, and (3) evaluate the plant's readiness to resume operations. The panel, which is referred to as the Davis-Besse Oversight Panel, comprises officials from NRC's Region III office in Lisle, Illinois; NRC headquarters; and the resident inspector office at Davis-Besse. In addition to overseeing FirstEnergy's performance during the shutdown and through restart of Davis-Besse, the panel holds public meetings in Oak Harbor, Ohio, where the plant is located, and nearby Port Clinton, Ohio, to inform the public about its oversight of Davis-Besse's restart efforts and its views on the adequacy of these efforts. The panel developed a checklist of issues that FirstEnergy had to resolve prior to restarting: (1) replacing the vessel head and ensuring the adequacy of other equipment important for safety, (2) correcting FirstEnergy programs that led to the corrosion, and (3) ensuring FirstEnergy's readiness to restart. To restart the plant, FirstEnergy, among other things, removed the damaged reactor vessel head, purchased and installed a new head, replaced management at the plant, and took steps to improve key programs that should have prevented or detected the corrosion. As of March 2004, when NRC gave its approval for Davis-Besse to resume

[18]NRC has an Accident Sequence Precursor Analysis Program to analyze significant events that occur at nuclear power plants to determine how, and the likelihood that, the events could have led to core damage.

operations, the shutdown and preparations for restart had cost FirstEnergy approximately $640 million.[19]

In addition, NRC established a task force to evaluate its regulatory processes for assuring reactor pressure vessel head integrity and to identify and recommend areas for improvement that may be applicable to either NRC or the nuclear power industry. The task force's report, which was issued in September 2002, contains 51 recommendations aimed primarily at improving NRC's process for inspecting and overseeing licensees, communicating with industry, and identifying potential emerging technical issues that could impact plant safety. NRC developed an action plan to implement the report's recommendations.

NRC's Actions to Oversee Davis-Besse Did Not Provide an Accurate Assessment of Safety at the Plant

NRC's inspections and assessments of FirstEnergy's operations should have but did not provide the agency with an accurate understanding of safety conditions at Davis-Besse, and thus NRC failed to identify or prevent the vessel head corrosion. Some NRC inspectors were aware of the indications of corrosion and leakage that could have alerted NRC to corrosion problems at the plant, but they did not have the knowledge to recognize the significance of this information. These problems were compounded by NRC's assessments of FirstEnergy that led the agency to believe FirstEnergy was a good performer and could or would successfully resolve problems before they became significant safety issues. More broadly, NRC had a range of information that could have identified and prevented the incident at Davis-Besse but did not effectively integrate it into its oversight.

[19]FirstEnergy spent about $293 million on operations, maintenance, and capital projects (including $47 million for the new reactor vessel head) and $348 million to purchase power to replace the power that Davis-Besse would have generated over the 2-year shutdown period. In contrast, during a more routine refueling outage, Davis-Besse would spend about $60 million—about $37 million on operations, maintenance, and capital projects and $23 million on replacing the power that would have been generated over a 42-day shutdown period. These latter estimates are based on the Davis-Besse refueling outage in midcalendar year 2000.

Several Factors Contributed to the Inadequacy of NRC's Inspections for Determining Plant Conditions

Three separate, but related, NRC inspection program factors contributed to the development of the corrosion problems at Davis-Besse. First, resident inspectors did not know that the boric acid, rust, and unidentified leaking indicated that the reactor vessel head might be degrading. Second, these inspectors thought they understood the cause for the indications, based on licensee actions to address them. Therefore, resident inspectors, as well as regional and headquarters officials, did not fully communicate information on the indications or decide how to address them, and therefore took no action. Third, because the significance of the symptoms was not fully recognized, NRC did not direct sufficient inspector resources to aggressively investigate the indicators. NRC might have taken a different approach to the Davis-Besse situation if its program to identify emerging issues important to safety had pursued earlier concerns about boric acid corrosion and cracking and recognized how they could affect safety.

Inspectors Did Not Know Safety Significance of Observed Problems

NRC limits the amount of unidentified leakage from the reactor coolant system to no more than 1 gallon per minute. When this limit is exceeded, NRC requires that licensees identify and correct any sources of unidentified leakage. NRC also prohibits any leakage from the reactor coolant pressure boundary, of which the reactor vessel is a key component. Such leakage is prohibited because the pressure boundary is key to maintaining adequate coolant around the reactor fuel and thus protects public health and safety. Because of this, NRC's technical specification states that licensees are to monitor reactor coolant leakage and shut down within 36 hours if leakage is found in the pressure boundary.

In the years leading up to FirstEnergy's March 2002 discovery that Davis-Besse's vessel head had corroded extensively, NRC had several indications of potential leakage problems. First, NRC knew that the rates of leakage in the reactor coolant system had increased. Between 1995 and mid-1998, the unidentified leakage rate was about 0.06 gallon per minute or less, according to FirstEnergy's monitoring. In mid-1998, the unidentified reactor coolant system leakage rate increased significantly—to as much as 0.8 gallon per minute. The elevated leakage rate was dominated by a known problem with a leaking relief valve on the reactor coolant system pressurizer tank, which masked the ongoing leak on the reactor pressure vessel head. However, the elevated leak rate should have raised concerns.

To investigate this leakage, as well as to repair other equipment, FirstEnergy shut down the plant in mid-1999. It then identified a faulty relief valve that accounted for much of the leakage and repaired the valve.

However, after restarting Davis-Besse, the unidentified leakage rate remained significantly higher than the historical average. Specifically, the unidentified leakage rate varied between 0.15 and 0.25 gallon per minute as opposed to the historical low of about 0.06 gallon or less. While NRC was aware that the rate was higher than before, NRC did not aggressively pursue the difference because the rate was well below NRC's limit of no more than 1 gallon per minute, and thus the leak was not viewed as being a significant safety concern. Following the repair in 1999, NRC's inspection report concluded that FirstEnergy's efforts to reduce the leak rate during the outage were effective.

Second, NRC was aware of increased levels of boric acid in the containment building—an indication that components containing reactor coolant were leaking. So much boric acid was being deposited that FirstEnergy officials had to repeatedly clean the containment air cooling system and radiation monitor filters. For example, before 1998, the containment air coolers seldom needed cleaning, but FirstEnergy had to clean them 28 times between late 1998 and May 2001. Between May 2001 and the mid-February 2002 shutdown, the containment air coolers were not cleaned, but at shutdown, FirstEnergy removed 15 5-gallon buckets of boric acid from the coolers—which is almost as much as was found on the reactor pressure vessel head. Rather than seeing these repeated cleanings as an indication of a problem that needed to be addressed, FirstEnergy made cleaning the coolers a routine maintenance activity, which NRC did not consider significant enough to require additional inspections. Furthermore, the radiation monitors, used to sample air from the containment building to detect radiation, typically required new filters every month. However, from 1998 to 2002, these monitors became clogged and inoperable hundreds of times because of boric acid, despite FirstEnergy's efforts to fix the problem.

Third, NRC was aware that FirstEnergy found rust in the containment building. The radiation monitor filters had accumulated dark colored iron oxide particles—a product of carbon steel corrosion—that were likely to have resulted from a very small steam leak. NRC inspection reports during the summer and fall of 1999 noted these indications and, while recognizing FirstEnergy's aggressive attempts to identify the reasons for the phenomenon, concluded that they were a "distraction to plant personnel." Several NRC inspection reports noted indications of leakage, boric acid, and rust before the agency adopted its new Reactor Oversight Process in 2000, but because the leakage was within NRC's technical specifications and NRC officials thought that the licensee understood and would fix the problem, NRC did not aggressively pursue the indications. NRC's new oversight process, implemented in the spring of 2000, limited the issues that could be discussed in NRC inspection reports to those that the agency considers to have more than minor significance. Because the leakage rates were below NRC's limits, NRC's inspection reports following the implementation of NRC's new oversight process did not identify any discussion of these problems at the plant.

Fourth, NRC was aware that FirstEnergy found rust on the Davis-Besse reactor vessel head, but it did not recognize its significance. For instance, during the 2000 refueling outage, a FirstEnergy official said he showed one of the two NRC resident inspectors a report that included photographs of rust-colored boric acid on the vessel head. (See fig. 5.)

Figure 5: Rust and Boric Acid on Davis-Besse's Vessel Head as Shown to Resident Inspector during the 2000 Refueling Outage

Source: FirstEnergy.

According to this resident inspector, he did not recall seeing the report or photographs but had no reason to doubt the FirstEnergy official's statement. Regardless, he stated that had he seen the photographs, he would not have considered the condition to be significant at the time. He said that he did not know what the rust and boric acid might have indicated, and he assumed that FirstEnergy would take care of the vessel head before restarting. The second resident inspector said he reviewed all such reports at Davis-Besse but did not recall seeing the photographs or this particular report. He stated that it was quite possible that he had read the report, but because the licensee had a plan to clean the vessel head, he would have concluded that the licensee would correct the matter before plant restart. However, FirstEnergy did not accomplish this, even though work orders and subsequent licensee reports indicated that this was done. According to the NRC resident inspector and NRC regional officials, because of the large number of licensee activities that occur during a refueling outage, NRC inspectors do not have the time to investigate or follow up on every issue, particularly when the issue is not viewed as being important to safety. While the resident inspector informed regional officials about conditions at Davis-Besse, the regional office did not direct more inspection resources to the plant, or instruct the resident inspector to conduct more focused oversight. Some NRC regional officials were aware of indications of boric acid corrosion at the plant; others were not. According to the Office of the Inspector General's investigation and 2003 report on Davis-Besse,[20] the NRC regional branch chief—who supervised the staff responsible for overseeing FirstEnergy's vessel head inspection activities during the 2000 refueling outage—said that he was unaware of the boric acid leakage issues at Davis-Besse, including its effects on the containment air coolers and the radiation monitor filters. Had his staff been requested to look at these specific issues, he might have directed inspection resources to that area. (App. I provides a time line showing significant events of interest.)

NRC Did Not Fully Communicate Indications

NRC was not fully aware of the indications of a potential problem at Davis-Besse because NRC's process for transmitting information from resident inspectors to regional offices and headquarters did not ensure that information was fully communicated, evaluated, or used. NRC staff communicated information about plant operations through inspection reports, licensee assessments, and daily conference calls that included

[20]NRC, Office of the Inspector General, *NRC's Oversight of Davis-Besse during the April 2000 Refueling Outage* (Washington, D.C.: Oct. 17, 2003).

resident, regional, and headquarters officials. According to regional officials, information that is not considered important is not routinely communicated to NRC management and technical specialists. For example, while the resident inspectors at Davis-Besse knew all of the indications of leakage, and there was some level of knowledge about these indications at the regional office level, the knowledge was not sufficiently widespread within NRC to alert a technical specialist who might have recognized their safety significance. According to NRC Region III officials, the region uses an informal means—memorandums sent to other regions and headquarters—of communicating information identified at plants that it considers to be important to safety. However, because the indications at Davis-Besse were not considered important, officials did not transmit this information to headquarters. Further, because the process is informal, these officials said they did not know whether—and if so, how—other NRC regions or headquarters used this information.

Similarly, NRC officials said that NRC headquarters had no systematic process for communicating information, such as on boric acid corrosion, cracking, and small amounts of unidentified leakage, that had not yet risen to a relatively high level of concern within the agency, in a timely manner to its regions or on-site inspectors. For example, the regional inspector that oversaw FirstEnergy's activities during the 2000 refueling outage, including the reactor vessel head inspection, stated that he was not aware of NRC's generic bulletins and letters pertaining to boric acid and corrosion, even though NRC issues only a few of these bulletins and generic letters each year.[21] In addition, according to NRC regional officials and the resident inspector at Davis-Besse, there is little time to review technical reports about emerging safety issues that NRC compiles because they are too lengthy and detailed. Ineffective communication, both within the region and between NRC headquarters and the region, was a primary factor cited by NRC's Office of the Inspector General in its investigation of NRC's oversight of Davis-Besse boric acid leakage and corrosion.[22] For example, it found that ineffective communication resulted in senior regional management being largely unaware of repeated reports of boric acid leakage at Davis-Besse. It also found that headquarters, in communications with the regions, did not emphasize the issues discussed in its generic

[21]Over the last 10 years, NRC has issued an average of about two generic bulletins and about four generic letters a year.

[22]NRC, Office of the Inspector General, *NRC's Oversight of Davis-Besse during the April 2000 Refueling Outage* (Washington, D.C.; Oct. 17, 2003).

letters or bulletins on boric acid corrosion or cracking. NRC programs for informing its inspectors about issues that can reduce safety at nuclear power plants were not effective. As a result, NRC inspectors did not recognize the significance of the indications at Davis-Besse, fully communicate information about the indications, or spend additional effort to follow up on the indications.

Resource Constraints Affected NRC Oversight

NRC also did not focus on the indications that the vessel head was corroding because of several staff constraints. Region III was directing resources to other plants that had experienced problems throughout the region, and these plants thus were the subject of increased regulatory oversight. For example, during the refueling outages in 1998 and 2000, while NRC oversaw FirstEnergy's inspection of the reactor vessel head, the region lacked senior project engineers to devote to Davis-Besse. A vacancy existed for a senior project engineer responsible for Davis-Besse from June 1997 until June 1998, except for a one month period, and from September 1999 until May 2000, which resulted in fewer inspection hours at the facility than would have been normal. Other regional staff were also occupied with other plants in the region that were having difficulties, and NRC had unfilled vacancies for resident and regional inspector positions that strained resources for overseeing Davis-Besse.

Even if the inspector positions had been filled, it is not certain that the inspectors would have aggressively followed up on any of the indications. According to our discussions with resident and regional inspectors and our on-site review of plant activities, because nuclear power plants are so large, with many physical structures, systems, and components, an inspector could miss problems that were potentially significant for safety. Licensees typically prepare several hundred reports per month for identifying and resolving problems, and NRC inspectors have only a limited amount of time to follow up on these licensee reports. Consequently, NRC selects and oversees the most safety significant structures, systems, and components.

NRC's Assessment Process Did Not Indicate Deteriorating Performance

Under NRC's Reactor Oversight Process, NRC assesses licensees' performance using two distinct types of information: (1) NRC's inspection results and (2) performance indicators reported by the licensees. These indicators, which reflect various aspects of a plant's operations, include data on, for example, the failure or unavailability of certain important operating systems, the number of unplanned power changes, and the amount of reactor coolant system leakage. NRC evaluates both the inspection results and the performance indicators to arrive at licensee assessments, which it then color codes to reflect their safety significance. Green assessments indicate that performance is acceptable, and thus connote a very low risk significance and impact on safety. White, yellow, and red assessments each represent a greater degree of safety significance. After NRC adopted its Reactor Oversight Process in April 2000, FirstEnergy never received anything but green designations for its operations at Davis-Besse and was viewed by NRC as a good performer until the 2002 discovery of the vessel head corrosion.[23] Similarly, prior to adopting the Reactor Oversight Process, NRC consistently assessed FirstEnergy as generally being a good performer. NRC officials stated, however, that significant issues were identified and addressed as warranted throughout this period, such as when the agency took enforcement action in response to FirstEnergy's failure to properly repair important components in 1999—a failure caused by weaknesses in FirstEnergy's boric acid corrosion control program.

Key Davis-Besse programs for ensuring the quality and safe operation of the plant's engineered structures, systems, and components include, for example,

- a corrective action program to ensure that problems at the plant that are relevant to safety are identified and resolved in a timely manner,
- an operating experience program to ensure that experiences or problems that occur are appropriately identified and analyzed to determine their significance and relevance to operations, and
- a plant modification program to ensure that modifications important to safety are implemented in a timely manner.

As at other commercial nuclear power plants, NRC conducted routine, baseline inspections of Davis-Besse to determine the effectiveness of these programs. Reports documenting these inspections noted incidences of boric acid leakage, corrosion, and deposits. However, between February 1997 and March 2000, the regional office's assessment of the licensee's performance addressed leakage in the reactor coolant system only once and never noted the other indications. Furthermore, Davis-Besse was not

[23]Before adopting the Reactor Oversight Process, NRC also assessed licensee performance based on inspection results and other information; however, NRC did not assign color codes to assessment results.

the subject of intense scrutiny in regional plant assessment meetings because plants perceived as good performers—such as Davis-Besse—received substantially less attention. Between April 2000—when NRC's revised assessment process took effect—until the corrosion was discovered in March 2002, none of NRC's assessments of Davis-Besse's performance noted leakage or other indications of corrosion at the plant. As a result, NRC may have missed opportunities to identify weaknesses in the Davis-Besse programs intended to detect or prevent the corrosion.

After the corrosion was discovered, NRC analyzed the problems that led to the corrosion on the reactor vessel head and concluded that FirstEnergy's programs for overseeing safety at Davis-Besse were weak, as seen in the following examples:

- Davis-Besse's corrective action program did not result in timely or effective actions to prevent indications of leakage from reoccurring in the reactor coolant system.

- FirstEnergy officials did not always enter equipment problems into the corrective action program because individuals who had identified the problem were often responsible for resolving it.

- For over a decade, FirstEnergy had delayed plant modifications to its service structure platform, primarily because of cost. These modifications would have improved its ability to inspect the reactor vessel head nozzles. As a result, FirstEnergy could conduct only limited visual inspections and cleaning of the reactor pressure vessel head through the small "mouse-holes" that perforated the service structure.

NRC was also unaware of the extent to which various aspects of FirstEnergy's safety culture had degraded—that is, FirstEnergy's organization and performance related to ensuring safety at Davis-Besse. This degradation had allowed the incident to occur with no forewarning because NRC's inspections and performance indicators do not directly assess safety culture. Safety culture is a group of characteristics and attitudes within an organization that establish, as an overriding priority, that issues affecting nuclear plant safety receive the attention their significance warrants. Following FirstEnergy's March 2002 discovery, NRC found numerous indications that FirstEnergy emphasized production over plant safety. First, Davis-Besse routinely restarted the plant following an outage, even though reactor pressure vessel valves and control rod drive mechanisms leaked. Second, staff was unable to remove all of the boric acid deposits from the reactor pressure vessel head because FirstEnergy's schedule to restart the plant dictated the amount of work that could be performed. Third, FirstEnergy management was willing to accept degraded equipment, which indicated a lack of commitment to resolve issues that could potentially compromise safety. Fourth, Davis-Besse's program that was intended to ensure that employees feel free to raise safety concerns without fear of retaliation had several weaknesses. For example, in one instance, a worker assigned to repair the containment air conditioner was not provided a respirator in spite of his concerns that he would inhale boric acid residue. According to NRC's lessons-learned task force report, NRC was not aware of weaknesses in this program because its inspections did not adequately assess it.

Given that FirstEnergy concluded that one of the causes for the Davis-Besse incident was human performance and management failures, the panel overseeing FirstEnergy's efforts to restart Davis-Besse requested that FirstEnergy assess its safety culture before allowing the plant to restart. To oversee FirstEnergy's efforts to improve its safety culture, NRC (1) reviewed whether FirstEnergy had adequately identified all of the root causes for management and human performance failures at Davis-Besse, (2) assessed whether FirstEnergy had identified and implemented appropriate corrective actions to resolve these failures, and (3) assessed whether FirstEnergy's corrective actions were effective. As late as February 2004, NRC had concerns about whether FirstEnergy's actions would be adequate in the long term. As a result, the Davis-Besse safety culture was one of the issues contributing to the delay in restarting the plant. In March 2004, NRC's panel concluded that FirstEnergy's efforts to improve its safety culture were sufficient to allow the plant to restart. In doing so, however, NRC officials stated that one of the conditions the panel imposed was for FirstEnergy to conduct an independent assessment of the safety culture at Davis-Besse annually over the course of the next 5 years.

NRC Did Not Effectively Incorporate Long-Standing Knowledge about Corrosion, Nozzle Cracking, and Leak Detection into Its Oversight

NRC has been aware of boric acid corrosion and its potential to affect safety since at least 1979. It issued several notices to the nuclear power industry about boric acid corrosion and, specifically, the potential for it to degrade the reactor coolant pressure boundary. In 1987, two licensees found significant corrosion on their reactor pressure vessel heads, which heightened NRC's concern. A subsequent industry study concluded that concentrated solutions of boric acid could result in unacceptably high corrosion rates—up to 4 inches per year—when primary coolant leaks onto surfaces and concentrates at temperatures found on the surface of the reactor vessel.[24] After considering this information and several more instances of boric acid corrosion at plants, NRC issued a generic letter in 1988 requesting licensees to implement boric acid corrosion control programs.

In 1990, NRC visited Davis-Besse to assess the adequacy of the plant's boric acid corrosion control program. At that time, NRC concluded that the program was acceptable. However, in 1999, NRC became aware that FirstEnergy's boric acid corrosion control program was inadequate because boric acid had corroded several bolts on a valve, and NRC issued a violation. As a result of the violation, FirstEnergy agreed to review its boric acid corrosion procedures and enhance its program. NRC inspectors evaluated FirstEnergy's completed and planned actions to improve the boric acid corrosion control program and found them to be adequate. According to NRC officials, they never inspected the remaining actions—assuming that the planned actions had been implemented effectively. In 2000, NRC adopted its new Reactor Oversight Process and discontinued its inspection procedure for plants' corrosion control programs because these inspections had rarely been conducted due to higher priorities. Thus, NRC had no reliable or routine way to ensure that the nuclear power industry fully implemented boric acid corrosion control programs.

NRC also did not routinely review operating experiences at reactors, both in the United States and abroad, to keep abreast of boric acid developments and determine the need to emphasize this problem. Indeed, NRC did not fully understand the circumstances in which boric acid would result in corrosion, rather than flash to steam. Similarly, NRC did not know the rate at which carbon steel would corrode under different conditions. This lack of knowledge may be linked to shortcomings in its program to review operating experiences at reactors, which could have been exacerbated by the 1999 elimination of the office specifically responsible for reviewing operating experiences.[25] This office was responsible for, among other things, (1) coordinating operational data collection, (2)

[24]Westinghouse Electric Company, *Corrosion Effects of Boric Acid Leakage on Steel under Plant Operating Conditions—A Review of Available Data* (Pittsburgh: October 1987).

[25]NRC's Office for Analysis and Evaluation of Operating Data was established in response to a recommendation that we made to the agency in 1978 that it have a systematic process for analyzing operating experience and feeding this information back to licensees and the industry. NRC eliminated this office, and its responsibilities were transferred to other NRC offices in an effort to gain efficiencies.

systematically analyzing and evaluating operational experience, (3) providing feedback on operational experience to improve safety, (4) assessing the effectiveness of the agencywide program, and (5) acting as a focal point for interaction with outside organizations on issues pertaining to operational safety data analysis and evaluation. According to NRC officials who had overseen Davis-Besse at the time of the incident, they would not have suspected the reactor vessel head or cracked head penetration nozzles as the source of the filter clogging and unidentified leakage because they had not been informed that these could be potential problems. According to these officials, the vessel head was "not on the radar screen."

With regard to nozzle cracking, NRC, for more than two decades, was aware of the potential for nozzles and other components made of alloy 600 to crack. While cracks were found at nuclear power plants, NRC considered their safety significance to be low because the cracks were not developing rapidly. In contrast, other countries considered the safety significance of such cracks to be much higher. For example, concern over alloy 600 cracking led France, as a preventive measure, to institute requirements for an extensive nondestructive examination inspection program for vessel head penetration nozzles, including the removal of insulation, during every fuel outage. When any indications of cracking were observed, even more frequent inspections were required, which, because of economic considerations, resulted in the replacement of vessel heads when indications were found. The effort to replace the vessel heads is still under way. Japan replaced those vessel heads whose nozzles it considered most susceptible to cracking, even though no cracks had yet been found. Both France and Sweden also installed enhanced leakage monitoring systems to detect leaks early. However, according to NRC, such systems cannot detect the small amounts of leakage that may be typical from cracked nozzles.

NRC recognized that an integrated, long-term program, including periodic inspections and monitoring of vessel heads to check for nozzle cracking, was necessary. In 1997, it issued a generic letter that summarized NRC's efforts to address cracking of control rod drive mechanism nozzles and requested information on licensees' plans to inspect nozzles at their reactors. More specifically, this letter asked licensees to provide NRC with descriptions of their inspections of these nozzles and any plans for enhanced inspections to detect cracks. At that time, NRC was planning to review this information to determine if enhanced licensee inspections were warranted. Based on its review of this information, NRC concluded that the current inspection program was sufficient. As a result, between 1998 and

2001, NRC did not issue or solicit additional information on nozzle cracking or assess its requirements for inspecting reactor vessels to determine whether they were sufficient to detect cracks. At Davis-Besse, NRC also did not determine if FirstEnergy had plans or was implementing any plans for enhanced nozzle inspections, as noted in the 1997 generic letter. NRC took no further action until the cracks were found in 2001 at the Oconee plant, in South Carolina. NRC attributed its lack of focus on nozzle cracking, in part, to the agency's inability to effectively review, assess, and follow up on industry operating experience events. Furthermore, as with boric acid corrosion, NRC did not obtain or analyze any new data about cracking that would have supported making changes in either its regulations or inspections to better identify or prevent corrosion on the vessel head at Davis-Besse.

NRC's technical specifications regarding allowable leakage rates also contributed to the corrosion at Davis-Besse because the amount of leakage that can cause extensive corrosion can be significantly less than the level that NRC's specifications allow. According to NRC officials, NRC's requirements, established in 1973, were based on the best available technology at that time. The task of measuring identified and unidentified leakage from the reactor coolant system is not precise. It requires licensees to estimate the amount of coolant that the reactor is supposed to contain and identify any difference in coolant levels. They then have to account for the estimated difference in the actual amount of coolant to arrive at a leakage rate; to do this, they identify all sources and amounts of leakage by, among other things, measuring the amount of water contained in various sump collection systems. If these sources do not account for the difference, licensees know they have an unidentified source of leakage. This estimate can vary significantly from day to day between negative and positive numbers.

According to analyses that FirstEnergy conducted after it identified the corrosion in March 2002, the leakage rates from the nozzle cracks were significantly below NRC's reactor coolant system unidentified leakage rate of 1 gallon per minute. Specifically, the leakage from the nozzle around which the vessel head corrosion occurred was predicted to be 0.025 gallon per minute. If such small leakage can result in such extensive corrosion, identifying if and where such leakage occurs is important. NRC staff recognized as early as 1993 it would be prudent for the nuclear power industry to consider implementing an enhanced method for detecting small leaks during plant operation, but NRC did not require this action, and the industry has not taken steps to do so. Furthermore, NRC has not consistently enforced its requirement for reactor coolant pressure boundary leakage. As a result, the NRC Davis-Besse task force concluded that inconsistent enforcement may have reinforced a belief that alloy 600 nozzle leakage was not actually or potentially a safety significant issue.

NRC's Process for Deciding Whether to Allow a Delayed Davis-Besse Shutdown Lacked Credibility

Although FirstEnergy operated Davis-Besse without incident until shutting it down in February 2002, certain aspects of NRC's deliberations allowing the delayed shutdown raise questions about the credibility of the agency's decision making, if not about the Davis-Besse decision itself. NRC does not have specific guidance for deciding on plant shutdowns. Instead, agency officials turned to guidance developed for a different purpose—reviewing requests to amend license operating conditions—and even then did not always adhere to this guidance. In addition, NRC did not document its decision-making process, as called for by its guidance, and its letter to FirstEnergy to lay out the basis for the decision—sent a year after the decision—did not fully explain the decision. NRC's lack of guidance, coupled with the lack of documentation, precludes us from independently judging whether NRC's decision was reasonable. Finally, some NRC officials stated that the shutdown decision was based, in part, on the agency's probabilistic risk assessment (PRA) calculations of the risk that Davis-Besse would pose if it delayed its shutdown and inspection. However, as noted by our consultants, the calculations were flawed, and NRC's decision makers did not always follow the agency's guidance for developing and using such calculations.

NRC Did Not Have Specific Guidance for Deciding on Plant Shutdowns

NRC believed that Davis-Besse could have posed a potential safety risk because it was, in all likelihood, failing to comply with NRC's technical specification that no leakage occur in the reactor coolant pressure boundary. Its belief was based on the following indicators of probable leakage:

- All six of the other reactors manufactured by the same company as Davis-Besse's reactor had cracked nozzles and identified leakage.[26]

- Three of these six reactors had identified circumferential cracking.

[26]Davis-Besse's manufacturer was the Babcock and Wilcox Company, which is an operating unit of McDermott International.

- FirstEnergy had not performed a recent visual examination of all of its nozzles.

Furthermore, a FirstEnergy manager agreed that cracks and leakage were likely.

NRC has the authority to shut down a plant when it is clear that the plant is in violation of important safety requirements, and it is clear that the plant poses a risk to public health and safety.[27] Thus, if a licensee is not complying with technical specifications, such as those for no allowable reactor vessel pressure boundary leakage, NRC can order a plant to shut down. However, NRC decided that it could not require Davis-Besse to shut down on the basis of other plants' cracked nozzles and identified leakage or the manager's acknowledgement of a probable leak. Instead, it believed it needed more direct, or absolute, proof of a leak to order a shutdown. This standard of proof has been questioned. According to the Union of Concerned Scientists,[28] for example, if NRC needed irrefutable proof in every case of suspected problems, the agency would probably never issue a shutdown order. In effect, in this case NRC created a Catch-22: It needed irrefutable proof to order a shutdown but could not get this proof without shutting down the plant and requiring that the reactor be inspected.

Despite NRC's responsibility for ensuring that the public is adequately protected from accidents at commercial nuclear power plants, NRC does not have specific guidance for shutting down a plant when the plant may pose a risk to public health and safety, even though it may be complying with NRC requirements. It also has no specific guidance or standards for quality of evidence needed to determine that a plant may pose an undue risk. Lacking direct or absolute proof of leakage at Davis-Besse, NRC instead drafted a shutdown order on the basis that a potentially hazardous condition may have existed at the plant. NRC had no guidance for developing such a shutdown order, and therefore, it used its guidance for reviewing license amendment requests. NRC officials recognized that this guidance was not specifically designed to determine whether NRC should shut down a power plant such as Davis-Besse. However, NRC officials

[27]Ordinarily, NRC would not suspend a license for a failure to meet a requirement unless the failure was willful and adequate corrective action had not been taken.

[28]The Union of Concerned Scientists is a nonprofit partnership of scientists and citizens that augments scientific analyses and policy development for identifying environmental solutions to issues such as energy production.

stated that this guidance was the best available for deciding on a shutdown because, although the review was not to amend a license, the factors that NRC needed to consider in making the decision and that were contained in the guidance were applicable to the Davis-Besse situation.

To use its guidance for reviewing license amendment requests, NRC first determined that the situation at Davis-Besse posed a special circumstance because new information revealed a substantially greater potential for a known hazard to occur, even if Davis-Besse was in compliance with the technical specification for leakage from the reactor coolant pressure boundary. The special circumstance stemmed from NRC's determination that requirements for conducting vessel head inspections were not sufficient to detect nozzle cracking and, thus, small leaks.[29] According to NRC officials, this determination allowed NRC to use its guidance for reviewing license amendment requests when deciding whether to order a shutdown.

The Extent of NRC's Reliance on License Amendment Guidance Is Not Clear

Under NRC's license amendment guidance, NRC considers how the license change affects risk, but not how it has previously assessed licensee performance, such as whether the licensee was viewed as a good performer. With regard to the Davis-Besse decision, the guidance directed NRC to determine whether the plant would comply with five NRC safety principles if it operated beyond December 2001 without inspecting the reactor vessel head. As applied to Davis-Besse, these principles were whether the plant would (1) continue to meet requirements for vessel head inspections, (2) maintain sufficient defense-in-depth, (3) maintain sufficient safety margins, (4) have little increase in the likelihood of a core damage accident, and (5) monitor the vessel head and nozzles. The guidance, however, does not specify how to apply these safety principles, how NRC can demonstrate it has followed the principles and ensured they are met, or whether any one principle takes precedence over the others. The guidance also does not indicate what actions NRC or licensees should take if some or all of the principles are not met.

[29]Specifically, reactor vessel head inspection requirements do not require that insulation be removed. Because of this, reactor vessel head inspections performed without removing the insulation above the vessel head could not result in 100 percent of the nozzles being visually inspected.

In mid-September 2001, NRC staff concluded that Davis-Besse complied with the first safety principle but did not meet the remaining four. According to the staff, Davis-Besse did not meet three safety principles because the requirements for vessel head inspections were not adequate. Specifically, the requirements do not require the inspector to remove the insulation above the vessel head, and thus allow all of the nozzles to be visually inspected. NRC therefore could not ensure that FirstEnergy was maintaining defense-in-depth and adequate safety margins or sufficiently monitoring the vessel head and nozzles. The staff believed that Davis-Besse did not meet the fourth safety principle because the risk estimate of core damage approached an unacceptable level and the estimate itself was highly uncertain.

Between early October and the end of November 2001, NRC requested and received additional information from FirstEnergy regarding its risk estimate of core damage—its PRA estimate—and met with the company to determine the basis for the estimate. NRC was also developing its own risk estimate, although its numbers kept changing. At some point during this time, NRC staff also concluded that the first safety principle was probably not being met, although the basis for this conclusion is not known.

At the end of November 2001, NRC contacted FirstEnergy and informed it that a shutdown order had been forwarded to the NRC commissioners and asked if FirstEnergy could take any actions that would persuade NRC to not issue the shutdown order. The following day, FirstEnergy proposed measures to mitigate the potential for and consequences of an accident. These measures included, among other things, lowering the operating temperature from 605 degrees Fahrenheit to 598 degrees Fahrenheit to reduce the driving force for stress corrosion cracking on the nozzles, identifying a specific operator to initiate emergency cooling in response to an accident, and moving the scheduled refueling outage up from March 31, 2002, to no later than February 16, 2002. NRC staff discussed these measures, and NRC management asked the staff if they were concerned about extending Davis-Besse's operations until mid-February 2002. While some of the staff were concerned about continued operations, none indicated to NRC management that cracking in control rod drive mechanism nozzles was likely extensive enough to cause a nozzle to eject from the vessel head, thus making it unsafe to operate. NRC formally accepted FirstEnergy's compromise proposal within several days, thus abandoning its shutdown order.

NRC Did Not Fully Explain or Document the Basis for Its Decision

We could not fully assess NRC's basis for accepting FirstEnergy's proposal. NRC did not document its deliberations, even though its guidance requires that it do so. This documentation is to include the data, methods, and assessment criteria used; the basis for the decisions made; and essential correspondence sufficient to document the persons, places, and matters dealt with by NRC. Specifically, the guidance requires that the documentation contain sufficient detail to make possible a "proper scrutiny" of NRC decisions by authorized outside agencies and provide evidence of how basic decisions were formed, including oral decisions. NRC's guidance also states that NRC should document all important staff meetings.

In reviewing NRC's documentation on the Davis-Besse decision, we found no evidence of an in-depth or formal analysis of how Davis-Besse's proposed measures would affect the plant's ability to satisfy the five safety principles. Thus, it is unclear whether the safety principles contained in the guidance were met by the measures that FirstEnergy proposed. However, several NRC officials stated that FirstEnergy's proposed measures had no impact on plant operations or safety. For example, according to one NRC official, FirstEnergy's proposal to reduce the operating temperature would have had little impact on safety because the small drop in operating temperature over a 7-week period would have had little effect on the growth rate of any cracks in a nozzle. As such, this official considered the measures as "window dressing." A proposed measure that NRC staff did consider as having a significant impact on the risk was for FirstEnergy to dedicate an operator for manually turning on safety equipment in the event that a nozzle was ejected. Subsequent to approving the delayed shutdown, NRC learned that FirstEnergy had not, in fact, planned to dedicate an operator for this task—rather, FirstEnergy planned to have an operator do this task in addition to other regularly assigned duties.

According to an NRC official, once NRC decided not to issue a shutdown order for December 2001, NRC staff needed to discuss how NRC's assessment of whether the five safety principles had been met had changed in the course of the staff's deliberations. However, there was no evidence in the agency's records to support that this discussion was held, and other key meetings, such as the one in which the agency made its decision to allow Davis-Besse to operate past December 31, 2001, were not documented. Without documentation, it is not clear what factors influenced NRC's decision. For example, according to the NRC Office of the Inspector General's December 2002 report that examined the Davis-Besse incident, NRC's decision was driven in large part by a desire to lessen the financial impact on FirstEnergy that would result from an early shutdown.[30] While NRC disputed this finding, we found no evidence in the agency's records to support or refute its position.

In December 2001, when NRC informed FirstEnergy that it accepted the company's proposed measures and the February 16, 2002, shutdown date, it also said that the company would receive NRC's assessment in the near future. However, NRC did not provide the assessment until a full year later—in December 2002. In addition, the December 2002 assessment, which includes a four-page evaluation, does not fully explain how the safety principles were used or met—other than by stating that if the likelihood of nozzle failure were judged to be small, then adequate protection would be ensured. Even though NRC's regulations regarding the reactor coolant pressure boundary dictate that the reactor have an extremely low probability of failing, NRC stated it did not believe that Davis-Besse needed to demonstrate strict conformance with this regulation. As evidence of the small likelihood of failure, NRC cited the small size of cracks found at other power plants, as well as its preliminary assessment of nozzle cracking, which projected crack growth rates. NRC concluded that 7 weeks of additional operation would not result in an appreciable increase in the size of the cracks.[31] While NRC included its calculated estimates of the risk that Davis-Besse would pose, it did not detail how it calculated its estimates.

NRC's PRA Estimate Was Flawed and Its Use in Deciding to Delay the Shutdown Is Unclear

In moving forward with its more risk-informed regulatory approach, NRC has established a policy to increase the use of PRA methods as a means to promote regulatory stability and efficiency. Using PRA methods, NRC and the nuclear power industry can estimate the likelihood that different accident scenarios at nuclear power plants will result in reactor core damage and a release of radioactive materials. For example, one of these accident scenarios begins with a "medium break" loss-of-coolant accident in which the reactor coolant system is breached and a midsize—about 2- to 4-inch—hole is formed that allows coolant to escape from the reactor

[30]NRC, Office of the Inspector General, *NRC's Regulation of Davis-Besse Regarding Damage to the Reactor Vessel Head* (Washington, D.C.; Dec. 30, 2002).

[31]NRC, *Preliminary Staff Technical Assessment for Pressurized Water Reactor Vessel Head Penetration Nozzles Associated with NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles"* (Washington, D.C.; Nov. 6, 2001).

pressure boundary. The probability of such an accident scenario occurring and the consequences of that accident take into account key engineering safety system failure rates and human error probabilities that influence how well the engineered systems would be able to mitigate the consequences of an accident and ensure no radioactive release from the plant.

For Davis-Besse, NRC needed two estimates: one for the frequency of a nozzle ejecting and causing a loss-of-coolant accident and one for the probability that a loss-of-coolant accident would result in core damage. NRC first established an estimate, based partially on information provided by FirstEnergy, for the frequency of a plant developing a cracked nozzle that would initiate a medium break loss-of-coolant accident. NRC estimated that the frequency of this occurring would be about $2x10^{-2}$, or 1 chance in 50,[32] per year. NRC then used an estimate, which FirstEnergy provided, for the probability of core damage given a medium break loss-of-coolant accident. This probability estimate was $2.7x10^{-3}$, or about 1 chance in 370.[33] Multiplying these two numbers, NRC estimated that the potential for a nozzle to crack and cause a loss-of-coolant accident would increase the frequency of core damage at Davis-Besse by about $5.4x10^{-5}$ per year, or about 1 in 18,500 per year.[34] Converting this frequency to a probability associated with continued operation for 7 weeks, NRC calculated that the increase in the probability of core damage was approximately $5x10^{-6}$, or 1 chance in 200,000.[35] While NRC officials currently disagree that this was the number it used, this is the number that it included in its December 2002 assessment provided to FirstEnergy. Further, we found no evidence in the agency's records to support NRC's current assertion.

According to our consultants, the way NRC calculated and used the PRA estimate was inadequate in several respects. (See app. II for the consultants' detailed report.) First, NRC's calculations did not take into

[32]Here is how to calculate the frequency estimate: $2x10^{-2}$ equates to 0.02, or 2/100, which equals 1/50.

[33]Here is how to calculate the probability estimate: $2.7x10^{-3}$ equates to 0.0027, or 27/10,000, which equals 1/370.37.

[34]Here is how to calculate the frequency estimate: $5.4x10^{-5}$ equates to 0.000054, or 54/1,000,000, which equals 1/18,518.52.

[35]Here is how to calculate the probability estimate: $5x10^{-6}$ equates to 0.000005, or 5/1,000,000, which equals 1/200,000.

account several factors, such as the possibility of corrosion and axial cracking that could lead to leakage. For example, the consultants concluded that NRC's estimate of risk was incorrectly too small, primarily because the calculation did not consider corrosion of the vessel head. In reviewing how NRC developed and used its PRA estimates for Davis-Besse, our consultants noted that the calculated risk was smaller than it should have been because the calculations did not consider corrosion of the reactor vessel from the boric acid coolant leaking through cracks in the nozzles. According to the consultants, apparently all NRC staff involved in the Davis-Besse decision were aware that coolant under high pressure was leaking from valves, flanges, and possibly from cracks but evidently thought that the coolant would immediately flash into steam and noncorrosive compounds of boric acid. Our consultants, however, stated that because boric acid could potentially cause corrosion, except at temperatures much higher than 600 degrees Fahrenheit, NRC should have anticipated that corrosion could occur. Our consultants further stated that as evaporation occurs, boric acid becomes more concentrated in the remaining liquid—making it far more corrosive—and as vapor pressure decreases, evaporation is further slowed. They said it should be expected that some of the boric acid in the escaping coolant could reach the metal surfaces as wet or moist, highly corrosive material underlying the surface layers of dry noncorrosive boric acid, which is evidently what happened at Davis-Besse.

Our consultants concluded that NRC staff should have been aware of the experience at French nuclear power plants, where boric acid corrosion from leaking reactor coolant had been identified during the previous decade, the safety significance had been recognized, and safety procedures to mitigate the problem had been implemented. Furthermore, tests had been conducted by the nuclear power industry and in government laboratories on boric acid corrosion that were widely available to NRC. They stated that keeping abreast of safety issues at similar plants, whether domestic or foreign, and conveying relevant safety information to licensees are important functions of NRC's safety program. According to NRC, the agency was aware of the experience at French nuclear power plants. For example, NRC concluded, in a December 15, 1994, internal NRC memo, that primary coolant leakage from a through-wall crack could cause boric acid corrosion of the vessel head. However, because it concluded that some analyses indicated that it would take at least 6 to 9 years before any corrosion would challenge the structural integrity of the head, NRC concluded that cracking was not a short-term safety issue.

Our consultants also stated that NRC's risk analysis was inadequate because the analysis concerned only the formation and propagation of circumferential cracks that could result in nozzle failure, loss of coolant, and even control rod ejection. Although there is less chance of axial cracks causing complete nozzle failure, these cracks open additional pathways for coolant leakage. In addition, their long crevices provide considerably greater opportunity for the coolant to concentrate near the surface of the vessel head. However, according to our consultants, NRC was convinced that the boric acid they saw resulted from leaking flanges above the reactor vessel head, as opposed to axial cracks in the nozzles.

Second, NRC's analysis was inadequate because it did not include the uncertainty of its risk estimate and use the uncertainty analysis in the Davis-Besse decision-making process, although NRC staff should have recognized large uncertainties associated with its risk estimate. Our consultants also concluded that NRC failed to take into account the large uncertainties associated with estimates of the frequency of core damage resulting from the failure of nozzles. PRA estimates for nuclear power plants are subject to significant uncertainties associated with human errors and other common causes of system component failures, and it is important that proper uncertainty analyses be performed for any PRA study. NRC guidance and other NRC reports on advancing PRA technology for risk-informed decisions emphasize the need to understand and characterize uncertainties in PRA estimates. Our consultants stated that had the NRC staff estimated the margin of error or uncertainty associated with its PRA estimate for Davis-Besse, the uncertainty would likely have been so high as to render the estimate of questionable value.

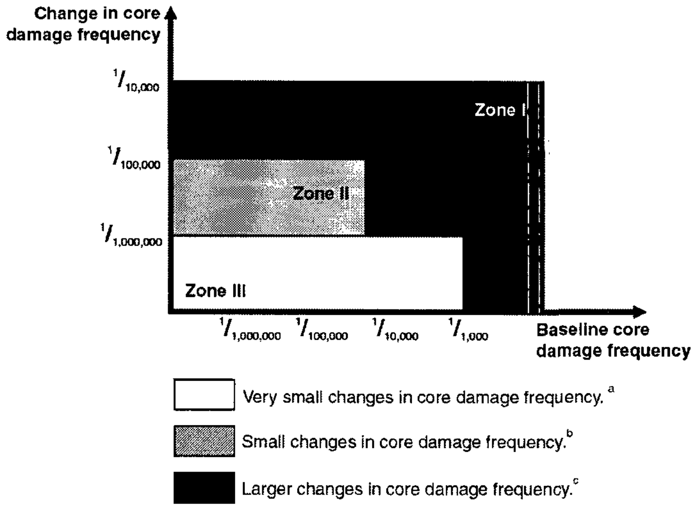
Third, NRC's analysis was inadequate because the risk estimates were higher than generally considered acceptable under NRC guidance. Despite PRA's important role in the decision, our consultants found that NRC did not follow its own guidance for ensuring that the estimated risk was within levels acceptable to the agency. NRC required the nuclear power industry to develop a baseline estimate for how frequently a core damage accident could occur at every nuclear power plant in the United States. This baseline estimate is used as a basis for deciding whether changes at a plant that affect the core damage frequency are acceptable. The baseline core damage frequency estimate for the Davis-Besse plant was between $4x10^{-5}$

and $6.6x10^{-5}$ per year (which is between 1 chance in 25,000[36] per year and about 1 chance in 15,150[37] per year). NRC guidance for reviewing and approving license amendment requests indicates that any plant-specific change resulting in an increase in the frequency of core damage of $1x10^{-5}$ per year (which is 1 chance in 100,000 per year) or more would fall within the highest risk zone: In this case, NRC would generally not approve the change because the risk criterion would not be met. If a license change would result in a core damage frequency change of $1x10^{-5}$ per year to $1x10^{-6}$ per year (which is 1 chance in 100,000 per year to 1 chance in 1 million per year), the risk criterion would be considered marginally met and NRC would consider approving the change but would require additional analysis. Finally, if a license change would result in a core damage frequency change of $1x10^{-6}$ per year (which is 1 chance in 1 million per year) or less, the risk would fall within the lowest risk zone and NRC would consider the risk criterion to be met and would generally consider approving the change without requiring additional analysis. (See fig. 6.)

[36]Here is how to calculate the frequency estimate: $4x10^{-5}$ equates to 0.00004, or 4/100,000, which equals 1/25,000.

[37]Here is how to calculate the frequency estimate: $6.6x10^{-5}$ equates to 0.000066, or 66/1,000,000, which equals 1/15,151.51.

Figure 6: NRC's Acceptance Guidelines for Core Damage Frequency



Source: NRC.

[a]Risk criterion is met and license changes would generally be considered.

[b]Risk criterion is considered marginally met and while license changes are generally considered, they require additional analysis.

[c]Risk criterion is not met and license changes are generally not allowed.

However, NRC's PRA estimate for Davis-Besse—an increase in the frequency of core damage of $5.4x10^{-5}$, or 1 chance in about 18,500 per year—was higher than the acceptable level. While an NRC official who helped develop the risk estimate said that additional NRC and industry guidance was used to evaluate whether its PRA estimate was acceptable, this guidance also suggests that NRC's estimate was too high. NRC's estimate of the increase in the frequency of core damage of $5.4x10^{-5}$ per year equates to an increase in the probability of core damage of $5x10^{-6}$, or 1 chance in 200,000, for the 7-week period December 31, 2001, to February 16, 2002.[35] NRC's guidance for evaluating requests to relax NRC technical specifications suggests that a probability increase higher than $5x10^{-7}$, or 1 chance in 2 million[38], is considered unacceptable for relaxing the specifications. Thus, NRC's estimate would not be considered acceptable

[38]Here is how to calculate the probability estimate: $5x10^{-7}$ equates to 0.0000005, or 5/10,000,000, which equals 1/2,000,000.

under this guidance. NRC's estimate would also not be considered acceptable under Electric Power Research Institute or Nuclear Energy Institute guidance unless further action were taken to evaluate or manage risk. According to NRC officials, NRC viewed its PRA estimate as being within acceptable bounds because it was a temporary situation—7 weeks—and NRC had, at other times, allowed much higher levels of risk at other plants. However, at the time that NRC made its decision, it did not document the basis for accepting this risk estimate, even though NRC's guidance explicitly states that the decision on whether PRA results are acceptable must be based on a full understanding of the contributors to the PRA results and the reasoning must be well documented. In defense of its decision, NRC officials said that the process they used to arrive at the decision is used to make about 1,500 licensing decisions such as this each year.

Lastly, NRC's analysis was inadequate because the agency does not have clear guidance for how PRA estimates are to be used in the decision-making process. Our consultants concluded that NRC's process for risk-informed decision making is ill-defined, lacks guidelines for how it is supposed to work, and is not uniformly transparent within NRC. According to NRC officials involved in the Davis-Besse decision, NRC's guidance is not clear on the use of PRA in the decision-making process. For example, while NRC has extensive guidance, this guidance does not outline to what extent or how the resultant PRA risk number and uncertainty should be weighed with respect to the ultimate decision. One factor complicating this issue is the lack of a predetermined methodology to weigh risks expressed in PRA numbers against traditional deterministic results and other factors.[39] Absent this guidance, the value assigned to the PRA analysis is largely at the discretion of the decision maker. The process, which NRC stated is robust, can result in a decision in which PRA played no role, a partial role, or one in which it was the sole deciding factor. According to our consultants, this situation is made worse by the lack of guidelines for how, or by whom, decisions in general are made at NRC.

It is not clear how NRC staff used the PRA risk estimate in the Davis-Besse decision-making process. For example, according to one NRC official who

[39]The deterministic approach considers a set of safety challenges and how those challenges should be mitigated through engineering safety margins and quality assurance standards. The probabilistic approach extends this by allowing for the consideration of a broader set of safety challenges, prioritizing safety challenges based on risk significance, and allowing for a broader set of mitigation mechanisms.

was familiar with some of the data on nozzle cracking, these data were not sufficient for making a good probabilistic decision. He stated that he favored issuing an order requiring that Davis-Besse be shut down by the end of December 2001 because he believed the available data were not sufficient to assure a low enough probability for a nozzle to be ejected. Other officials indicated that they accepted FirstEnergy's proposed February 16, 2002, shutdown date based largely on NRC's PRA estimate for a nozzle to crack and be ejected. According to one of these officials, allowing the additional 7 weeks of operating time was not sufficiently risk significant under NRC's guidance. He stated that safety margins at the plant were preserved and the PRA number was within an acceptable range. Still another official said he discounted the PRA estimate and did not use it at all when recommending that NRC accept FirstEnergy's compromise proposal. This official also stated that it was likely that many of the staff did base their conclusions on the PRA estimate. According to our consultants, although the extent to which the PRA risk analysis influenced the decision making will probably never be known, it is apparent that it did play an important role in the decision to allow the shutdown delay.

NRC Has Made Progress in Implementing Recommended Changes, but Is Not Addressing Important Systemic Issues

NRC has made significant progress in implementing the actions recommended by the Davis-Besse lessons-learned task force. While NRC has implemented slightly less than half—21 of the 51—recommendations as of March 2004, it is scheduled to have more than 70 percent of them implemented by the end of 2004. For example, NRC has already taken actions to improve staff training and inspections that would appear to help address the concern that NRC inspectors viewed FirstEnergy as a good performer and thus did not subject Davis-Besse to the level of scrutiny or questioning that they should have. It is not certain when actions to implement the remaining recommendations will occur, in part because of resource constraints. NRC also faces challenges in fully implementing the recommendations, also in part because of resource constraints, both in the staff needed to develop specific corrective actions and in the additional staff responsibilities and duties to carry them out. Further, while NRC is making progress, the agency is not addressing three systemic issues highlighted by the Davis-Besse experience: (1) an inability to detect weakness or deterioration in FirstEnergy's safety culture, (2) deficiencies in NRC's process for deciding on a shutdown, and (3) lack of management controls to track, on a longer-term basis, the effectiveness of actions implemented in response to incidents such as Davis-Besse, so that they do not occur at another power plant.

NRC Does Not Expect to Complete Its Actions until 2006, in Part Because of Resource Constraints

NRC's lessons-learned task force for Davis-Besse developed 51 recommendations to address the weaknesses that contributed to the Davis-Besse incident. Of these 51 recommendations, NRC rejected 2 because it concluded that agency processes or procedures already provided for the recommendations' intent to be effectively carried out.[40] To address the remaining 49 recommendations, NRC developed a plan in March 2003 that included, for each recommendation, the actions to be taken, the responsible NRC office, and the schedule for completing the actions. When developing its schedule, NRC placed the highest priority on implementing recommendations that were most directly related to the underlying causes of the Davis-Besse incident as well as those recommendations responding to vessel head corrosion. NRC assigned a lower priority to the remaining recommendations, which were to be integrated into the planning activities of those NRC offices assigned responsibility for taking action on the recommendations. In assigning these differing priorities, NRC officials stated they recognized that the agency has many other pressing matters to address that are not related to the Davis-Besse incident, such as renewing operating licenses, and they did not want to divert resources away from these activities. (App. III contains a complete list of the task force's recommendations, NRC actions, and the status of the recommendations as of March 2004.)

To better track the status of the agency's actions to implement the recommendations, we split two of the 49 recommendations that NRC accepted into 4; therefore, our analysis reflects NRC's response to 51 recommendations. As shown in table 1, as of March 2004, NRC had made progress in implementing the recommendations, although some completion dates have slipped.

[40]These two recommendations were for NRC to (1) review how industry considers economic factors in making decisions to repair equipment and consider these factors in developing guidance for nonvisual inspections of vessel head penetration nozzles, and (2) revise the criteria for reviewing industry topical reports that have not been formally submitted to NRC for review but that have generic safety implications.

Table 1: Status of Davis-Besse Lessons-Learned Task Force Recommendations, as of March 2004

Status	Number of recommendations
Completed as of March 2004	21
Scheduled for completion April through December 2004	17
Scheduled for completion in 2005	6
Completion date yet to be determined	7
Total	**51**

Source: GAO analysis of NRC data.

Note: This table does not include the two recommendations NRC rejected.

As the table shows, as of March 2004, NRC had implemented 21 recommendations and scheduled another 17 for completion by December 2004. However, some slippage has already occurred in this schedule—primarily because of resource constraints—and NRC has rescheduled completion of some recommendations. NRC's time frames for completing the recommendations depend on several factors—the recommendations' priority, the amount of work required to develop and implement actions, and the need to first complete actions on other related recommendations.

Of the 21 implemented recommendations, 10 called upon NRC to revise or enhance its inspection guidance or training. For example, NRC revised the guidance it uses to assess the implementation of licensees' programs to identify and resolve problems before they affect operations. It took this action because the task force had concluded that FirstEnergy's weak corrective action program implementation was a major contributor to the Davis-Besse incident. NRC has also developed Web-based training modules to improve NRC inspectors' knowledge of boric acid corrosion and nozzle cracking. The other 11 completed recommendations concerned actions such as

- collecting and analyzing foreign and domestic information on alloy 600 nozzle cracking,
- fully implementing and revising guidance to better assure that licensees carry out their commitments to make operational changes, and
- establishing measurements for resident inspector staffing levels and requirements.

By the end of 2004, NRC expects to complete another 17 recommendations, 12 of which generally address broad oversight or programmatic issues, and 5 of which provide for additional inspection guidance and training. On the broader issues, for example, NRC is scheduled to complete a review of the effectiveness of its response to past NRC lessons-learned task force reports by April 2004. By December 2004, NRC expects to have a framework established for moving forward with implementing recommended improvements to its agencywide operating experience program.

In 2005, 4 of the 6 recommendations scheduled for completion concern leakage from the reactor coolant system. For example, NRC is to (1) develop guidance and criteria for assessing licensees' responses to increasing leakage levels and (2) determine whether licensees should install enhanced systems to detect leakage from the reactor coolant system. The fifth recommendation calls for NRC to inspect the adequacy of licensees' programs for controlling boric acid corrosion, and the final recommendation calls on NRC to assess the basis for canceling a series of inspection procedures in 2001.

NRC did not assign completion dates to 7 recommendations because, among other things, their completion depends on completing other recommendations or because of limited resources. Even though it has not assigned completion dates for these recommendations, NRC has begun to work on 5 of the 7:

- Two recommendations will be addressed when requirements for vessel head inspections are revised. To date, NRC has taken some related, but temporary, actions. For example, since February 2003, it has required licensees to more extensively examine their reactor vessel heads. NRC has also issued a series of temporary instructions for NRC inspectors to oversee the enhanced examinations. NRC expects to replace these temporary steps with revised requirements for vessel head inspections.

- Two recommendations call upon NRC to revise requirements for detecting leaks in the reactor coolant pressure boundary. In response, NRC has, for example, begun to review its barrier integrity requirements and has contracted for research on enhanced detection capabilities.

- One recommendation is directed at improving follow-up of licensee actions taken in response to NRC generic communications. NRC is currently developing a temporary inspection procedure to assess the effectiveness of licensee actions taken in response to generic communications. Additionally, as a long-term change in the operating experience program, the agency plans to improve the verification of how effective its generic communications are.

The remaining two recommendations address NRC's need to (1) evaluate the adequacy of methods for analyzing the risks posed by passive components, such as reactor vessels, and integrate these methods and risks into NRC's decision-making process and (2) review a sample of plant assessments conducted between 1998 and 2000 to determine if any identified plant safety issues have not been adequately assessed. NRC has not yet taken action on these recommendations.

Some recommendations will require substantial resources to develop and implement. As a result, some implementation dates have slipped and some plans in response to the recommendations have changed in scope. For example, owing to resource constraints, NRC has postponed indefinitely the evaluation of methods to analyze the risk associated with passive reactor components such as the vessel head. Also, in part due to resource constraints, NRC has reconceptualized its plan to review licensee actions in response to previous generic communications, such as bulletins and letters.

Staff resources will be strained because implementing the recommendations adds additional responsibilities or duties—that is, more inspections, training, and reviews of licensee reports. For example, NRC's revised inspection guidance for more thorough examinations of reactor vessel heads and nozzles, as well as new requirements for NRC oversight of licensees' corrective action programs, will require at least an additional 200 hours of inspection per reactor per year. As of February 2004, NRC was also revising other inspection requirements that are likely to place additional demands on inspectors' time. Thus, to respond to these increased demands, NRC will either need to add inspectors or reduce oversight of other licensee activities.

To its credit, in its 2004 budget plan, NRC increased the level of resources for some inspection activities. However, it is not certain that these increases will be maintained. The number of inspection hours has fallen by more than one-third between 1995 and 2001. In addition, NRC is aware that resident inspector vacancies are filled with staff having varying levels of experience—from the basic level that would be expected from a newly qualified inspector to the advanced level that is achieved after several years' experience. According to the latest available data, as of May 2003, about 12 percent of sites had only one resident inspector; the remaining 88 percent had two inspectors of varying levels of experience. Because of this situation, NRC augments these inspection resources with regional inspectors and contractors to ensure that, at a minimum, its baseline inspection program can be implemented throughout the year. Because of surges in the demand for inspections, NRC in 2003 increased its use of contractors and temporarily pulled qualified inspectors from other jobs to help complete the baseline inspection program for every plant. According to NRC, it did not expect to require such measures in 2004.

Similarly, NRC may require additional staff to identify and evaluate plants' operating experiences and communicate the results to licensees, as the task force recommended. NRC has currently budgeted an increase of three full-time staff in fiscal year 2006 to implement a centralized system, or clearinghouse, for managing the operating experience program. However, according to an NRC official, questions remain about the level of resources needed to fully implement the task force recommendations. NRC's operating experience office, before it was disbanded in 1999, had about 33 staff whose primary responsibility was to collect, evaluate, and communicate activities associated with safety performance trends, as reflected in licensees' operating experiences, and participate in developing rulemakings. However, it is too early to know the effectiveness of this clearinghouse approach and the adequacy of resources in the other offices available for collecting and analyzing operating experience information. Neither the operating experience office before it was disbanded nor the other offices flagged boric acid corrosion, cracking, or leakage as problems warranting significantly greater oversight by NRC, licensees, or the nuclear power industry.

NRC Has Not Proposed Any Specific Actions to Correct Systemic Weaknesses in Oversight and Decision-Making Processes

NRC's Davis-Besse task force did not make any recommendations to address two systemic problems: evaluating licensees' commitment to safety and improving the agency's process for deciding on a shutdown.

NRC's Task Force Recommendations Did Not Address Licensee Safety Culture

NRC's task force identified numerous problems at Davis-Besse that indicated human performance and management failures and concluded that FirstEnergy did not foster an environment that was fully conducive to ensuring that plant safety issues received appropriate attention. Although the task force report did not use the term safety culture, as evidence of FirstEnergy's safety culture problems, the task force pointed to

- an imbalance between production and safety, as evidenced by FirstEnergy's efforts to address symptoms (such as regular cleanup of boric acid deposits) rather than causes (finding the source of the leaks during refueling outages);
- a lack of management involvement in or oversight of work at Davis-Besse that was important for maintaining safety;
- a lack of a questioning attitude by senior FirstEnergy managers with regard to vessel head inspections and cleaning activities;
- ineffective and untimely corrective action;
- a long-standing acceptance of degraded equipment; and
- inadequate engineering rigor.

The task force concluded that NRC's implementation of guidance for inspecting and assessing a safety-conscious work environment and employee concerns programs failed to identify significant safety problems. Although the task force did not make any specific recommendations that NRC develop a means to assess licensees' safety culture, it did recommend changes to focus more effort on assessing programs to promote a safety-conscious work environment.

NRC has taken little direct action in response to this task force recommendation. However, to help enhance NRC's capability to assess licensee safety culture by indirect means, NRC modified the wording in, and revised its inspection procedure for, assessing licensees' ability to identify and resolve problems, such as malfunctioning plant equipment. These revisions included requiring inspectors to

- review all licensee reports on plant conditions,
- analyze trends in plant conditions to determine the existence of potentially significant safety issues, and
- expand the scope of their reviews to the prior 5 years in order to identify recurring issues.

This problem identification and resolution inspection procedure is intended to assess the end results of management's safety commitment rather than the commitment itself. However, by measuring only the end results, early signs of a deteriorating safety culture and declining management performance may not be readily visible and may be hard to interpret until clear violations of NRC's regulations occur. Furthermore, because NRC directs its inspections at problems that it recognizes as being more important to safety, NRC may overlook other problems until they develop into significant and immediate safety problems. Conditions at a plant can quickly degrade to the extent that they can compromise public health and safety.

The International Atomic Energy Agency and its member nations have developed guidance and procedures for assessing safety culture at nuclear power plants, and today several countries, such as Brazil, Canada, Finland, Sweden, and the United Kingdom, assess plant safety culture or licensees' own assessments of their safety culture.[41] In assessing safety culture, an advisory group to the agency suggests that regulatory agencies examine whether, for example, (1) employee workloads are not excessive, (2) staff training is sufficient, (3) responsibility for safety has been clearly assigned within the organization, (4) the corporation has clearly communicated its safety policy, and (5) managers sufficiently emphasize safety during plant meetings. One reason for assessing safety culture, according to the Canadian Nuclear Safety Commission, is because management and human performance aspects are among the leading causes of unplanned events at licensed nuclear facilities, particularly in light of pressures such as deregulation of the electricity market. Finland specifically requires that nuclear power plants maintain an advanced safety culture and its inspections target the importance that has been embedded in factors affecting safety, including management. NRC had begun considering methods for assessing organizational factors, including safety culture, but in 1998, NRC's commissioners decided that the agency should have a performance-based inspection program of overall plant performance and should infer licensee management performance and competency from the results of that program. They chose this approach instead of one of four other options:

[41]The International Atomic Energy Agency is an international organization affiliated with the United Nations that provides advice and assistance to its members on nuclear safety matters.

- conduct performance-based inspections in all areas of facility operation and design, but not infer or articulate conclusions regarding the performance of licensee management;

- assess the performance of licensee management through targeted operations-based inspections using specific inspection procedures, trained staff, and contractors to assess licensee management—a task that would require the development of inspection procedures and significant training—and to document inspection results;

- assess the performance of licensee management as part of the routine inspection program by specifically evaluating and documenting management performance attributes—a larger effort that would require the development of assessment tools to evaluate safety culture as well as additional resources; or

- assess the competency of licensee management by evaluating management competency attributes—an even larger effort that would require that implementation options and their impacts be assessed.

When adopting the proposal to infer licensee management performance from the results of its performance-based inspection program, NRC eliminated any resource expenditures specifically directed at developing a systematic method of inferring management performance and competency. NRC stated that it currently has a number of means to assess safety culture that provide indirect insights into licensee safety culture. These means include, for example, (1) insights from augmented inspection teams, (2) lessons-learned reviews, and (3) information obtained in the course of conducting inspections under the Reactor Oversight Process. However, insights from augmented inspection teams and lessons-learned reviews are reactionary and do not prevent problems such as those that occurred at Davis-Besse. Further, before the Davis-Besse incident, NRC assumed its oversight process would adequately identify problems with licensees' safety culture. However, NRC has no formalized process for collectively assessing information obtained in the course of its problem identification and resolution inspection to ensure that individual inspection results would identify poor management performance. NRC stated that its licensee assessments consider inputs such as inspection results and insights, correspondence to licensees related to inspection observations, input from resident inspectors, and the results of any special investigations. However, this information may not be sufficient to inform NRC of problems at a plant in advance of these problems becoming safety significant.

In part because of Davis-Besse, NRC's Advisory Committee on Reactor Safeguards[42] recommended that NRC again pursue the development of a methodology for assessing safety culture. It also asked NRC to consider expanding research to identify leading indicators of degradation in human performance and work to develop a consistent comprehensive methodology for quantifying human performance. During an October 2003 public meeting of the advisory committee's Human Performance Subcommittee, the subcommittee's members again reiterated the need for NRC to assess safety culture. Specifically, the members recognized that certain aspects of safety culture, such as beliefs, perceptions, and management philosophies, are ultimately the nuclear power industry's responsibility but stated that NRC should deal with patterns of behavior and human performance, as well as organizational structures and processes. At this meeting, NRC officials discussed potential safety culture indicators that NRC could use, including, among other things, how many times a problem recurs at a plant, timeliness in correcting problems, number of temporary modifications, and individual program and process error rates. Committee members recommended that NRC test various safety culture indicators to determine whether (1) such indicators should ultimately be incorporated into the Reactor Oversight Process and (2) a significance determination process could be developed for safety culture. As of March 2004, NRC had yet to respond to the advisory committee's recommendation.

Despite the lack of action to address safety culture issues, NRC's concern over FirstEnergy's safety culture at Davis-Besse was one of the last issues resolved before the agency approved Davis-Besse's restart. NRC undertook a series of inspections to examine Davis-Besse's safety culture and determine whether FirstEnergy had (1) correctly identified the underlying causes associated with its declining safety culture, (2) implemented appropriate actions to correct safety culture problems, and (3) developed a process for monitoring to ensure that actions taken were effective for resolving safety culture problems. In December 2003, NRC noted significant improvements in the safety culture at Davis-Besse, but expressed concern with the sustainability of Davis-Besse's performance in this area. For example, a survey of FirstEnergy and contract employees conducted by FirstEnergy in November 2003 indicated that about 17

[42]The Advisory Committee on Reactor Safeguards is an independent committee comprising nuclear experts that advises NRC on matters of licensing and safety-related issues, and provides technical advice to aid the NRC commissioners' decision-making process.

percent of employees believed that management cared more about cost and schedule than resolving safety and quality issues—again, production over safety.

NRC's Task Force Recommendations Did Not Address NRC's Decision-Making Process

NRC's task force also did not analyze NRC's process for deciding not to order a shutdown of the Davis-Besse plant. It noted that NRC's written rationale for accepting FirstEnergy's justification for continued plant operation had not yet been prepared and recommended that NRC change guidance requiring NRC to adequately document such decisions. It also made a recommendation to strengthen guidance for verifying information provided by licensees. According to an NRC official on the task force, the task force did not assess the decision-making process in detail because the task force was charged with determining why the degradation at Davis-Besse was not prevented and because NRC had coordinated with NRC's Office of the Inspector General, which was reviewing NRC's decision making.

NRC's Failure to Track the Resolution of Identified Problems May Allow the Problems to Recur

The NRC task force conducted a preliminary review of prior lessons-learned task force reports to determine whether they suggested any recurring or similar problems. As a result of this preliminary review, the task force recommended that a more detailed review be conducted to determine if actions that NRC took as a result of those reviews were effective. These previous task force reports included: Indian Point 2 in Buchanan, New York, in February 2000; Millstone in Waterford, Connecticut, in October 1993; and South Texas Project in Wadsworth, Texas, from 1988 to 1994.[43] NRC's more detailed review, as of May 2004, was still under way. We also reviewed these reports to determine whether they suggested any recurring problems and found that they highlighted broad areas of continuing programmatic weaknesses, as seen in the following examples:

- *Inspector training and information sharing.* All three of the other task forces also identified inspector training issues and problems with information collection and sharing. The Indian Point task force called

[43]NRC formed the Indian Point lessons-learned task force in response to a steam-generator-tube rupture that forced a reactor shutdown. NRC formed the Millstone lessons-learned task force because the plant operated outside its design standards while refueling. NRC formed the South Texas task force in response to concerns about the effectiveness of NRC's inspection program and the adequacy of the licensee's employee concerns program.

upon NRC to develop a process for promptly disseminating technical information to NRC inspectors so that they can review and apply the information in their inspection program.

- *Oversight of licensee corrective action programs.* Two of the three task forces also identified inadequate oversight of licensee corrective action programs. The South Texas task force recommended improving assessments of licensees' corrective action programs to ensure that NRC identifies broader licensee problems.
- *Better identification of problems.* Two of the three task force reports also noted the need for NRC to develop a better process for identifying problem plants, and one report noted the need for NRC inspectors to more aggressively question licensees' activities.

Over the past two decades, we have also reported on underlying causes similar to those that contributed, in part, to the incident at Davis-Besse. (See Related GAO Products.) For example, with respect to the safety culture at nuclear power plants, in 1986, 1995, and 1997, we reported on issues relevant to NRC assessing plant management so that significant problems could be detected and corrected before they led to incidents such as the one that later occurred at Davis-Besse. Regardless of our 1997 recommendation that NRC require that the assessment of management's competency and performance be a mandatory component of NRC's inspection process, NRC subsequently withdrew funding to accomplish this. In terms of inspections, in 1995 we reported that NRC, itself, had concluded that the agency was not effectively integrating information on previously identified and long-standing issues to determine if the issues indicated systemic weaknesses in plant operations. This report further noted that NRC was not using such information to focus future inspection activities. In 1997 and 2001, we reported on weaknesses in NRC's inspections of licensees' corrective action programs. Finally, with respect to learning from plants' operating experiences, in 1984 we noted that NRC needed to improve its methods for consolidating information so that it could evaluate safety trends and ensure that generic issues are resolved at individual plants. These recurring issues indicate that NRC's actions, in response to individual plant incidents and recommendations to improve oversight, are not always institutionalized.

NRC guidance requires that resolutions to action plans be described and documented, and while NRC is monitoring the status of actions taken in response to Davis-Besse task force recommendations and preparing quarterly and semiannual reports on the status of actions taken, the Davis-Besse action plan does not specify how long NRC will monitor them. It also does not describe how long NRC will prepare quarterly and semiannual status reports, even though, according to NRC officials, these semiannual status reports will continue until all items are completed and the agency is required to issue a final summary report. The plan also does not specify what criteria the agency will use to determine when the actions in response to specific task force recommendations are completed. Furthermore, NRC's action plan does not require NRC to assess the long-term effectiveness of recommended actions, even though, according to NRC officials, some activities already have an effectiveness review included. As in the past and in response to prior lessons-learned task force reports and recommendations, NRC has no management control in place for assessing the long-term effectiveness of efforts resulting from the recommendations. NRC officials acknowledged the need for a management control, such as an agencywide tracking system, to ensure that actions taken in response to task force recommendations effectively resolve the underlying issue over the long term, but the officials have no plans to establish such a system.

Conclusions

It is unlikely, given the actions that NRC has taken to date, that extensive reactor vessel corrosion will occur any time soon at another domestic nuclear power plant. However, we do not yet have adequate assurances from NRC that many of the factors that contributed to the incident at Davis-Besse will be fully addressed. These factors include NRC's failure to keep abreast of safety significant issues by collecting information on operating experiences at plants, assessing their relative safety significance, and effectively communicating information within the agency to ensure that oversight is fully informed. The underlying causes of the Davis-Besse incident underscore the potential for another incident unrelated to boric acid corrosion or cracked control rod drive mechanism nozzles to occur. This potential is reinforced by the fact that both prior NRC lessons-learned task forces and we have found similar weaknesses in many of the same NRC programs that led to the Davis-Besse incident. NRC has not followed up on prior task force recommendations to assess whether the lessons learned were institutionalized. NRC's actions to implement the Davis-Besse lessons-learned task force recommendations, to be fully effective, will require an extensive effort on NRC's part to ensure that these are effectively incorporated into the agency's processes. However, NRC has not estimated the amount of resources necessary to carry out these recommendations, and we are concerned that resource limitations could constrain their effectiveness. For this reason, it is important for NRC to not only monitor the implementation of Davis-Besse task force recommendations, but also determine their effectiveness, in the long term, and the impact that resource constraints may have on them. These actions are even more important because the nation's fleet of nuclear power plants is aging.

Because the Davis-Besse task force did not address NRC's unwillingness to directly assess licensee safety culture, we are concerned that NRC's oversight will continue to be reactive rather than proactive. NRC's oversight can result in NRC making a determination that a licensee's performance is good one day, yet the next day NRC discovers the performance to be unacceptably risky to public health and safety. Such a situation does not occur overnight: Long-standing action or inaction on the part of the licensee causes unacceptably risky and degraded conditions. NRC needs better information to preclude such conditions. Given the complexity of nuclear power plants, the number of physical structures, systems, and components, and the manner in which NRC inspectors must sample to assess whether licensees are complying with NRC requirements and license specifications, it is possible that NRC will not identify licensees that value production over safety. While we recognize the difficulty in assessing licensee safety culture, we believe it is sufficiently important to develop a means to do so.

Given the limited information NRC had at the time and that an accident did not occur during the delay in Davis-Besse's shutdown, we do not necessarily question the decision the agency made. However, we are concerned about NRC's process for making that decision. It used guidance intended to make decisions for another purpose, did not rigorously apply the guidance, established an unrealistically high standard of evidence to issue a shutdown order, relied on incomplete and faulty PRA analyses and licensee evidence, and did not document key decisions and data. It is extremely unusual for NRC to order a nuclear power plant to shut down. Given this fact, it is more imperative that NRC have guidance to use when technical specifications or requirements may be met, yet questions arise over whether sufficient safety is being maintained. This guidance does not need to be a risk-based approach, but rather a more structured risk-informed approach that is sufficiently flexible to ensure that the guidance is applicable under different circumstances. This is important because NRC annually makes about 1,500 licensing decisions relating to operating commercial nuclear power plants. While we recognize the challenges NRC will face in developing such guidance, the large number and wide variety of decisions strongly highlight the need for NRC to ensure that its decision-making process and decisions are sound and defensible.

Recommendations for Executive Action

To ensure that NRC aggressively and comprehensively addresses the weaknesses that contributed to the Davis-Besse incident and could contribute to problems at nuclear power plants in the future, we are recommending that the NRC commissioners take the following five actions:

- Determine the resource implications of the task force's recommendations and reallocate the agency's resources, as appropriate, to better ensure that NRC effectively implements the recommendations.

- Develop a management control approach to track, on a long-term basis, implementation of the recommendations made by the Davis-Besse lessons-learned task force and future task forces. This approach, at a minimum, should assign accountability for implementing each recommendation and include information on the status of major actions, how each recommendation will be judged as completed, and how its effectiveness will be assessed. The approach should also provide for regular—quarterly or semiannual—reports to the NRC commissioners on the status of and obstacles to full implementation of the recommendations.

- Develop a methodology to assess licensees' safety culture that includes indicators of and inspection information on patterns of licensee performance, as well as on licensees' organization and processes. NRC should collect and analyze this data either during the course of the agency's routine inspection program or during separate targeted assessments, or during both routine and targeted inspections and assessments, to provide an early warning of deteriorating or declining performance and future safety problems.

- Develop specific guidance and a well-defined process for deciding on when to shut down a nuclear power plant. The guidance should clearly set out the process to be used, the safety-related factors to be considered, the weight that should be assigned to each factor, and the standards for judging the quality of the evidence considered.

- Improve NRC's use of probabilistic risk assessment estimates in decision making by (1) ensuring that the risk estimates, uncertainties, and assumptions made in developing the estimates are fully defined, documented, and communicated to NRC decision makers; and (2) providing guidance to decision makers on how to consider the relative importance, validity, and reliability of quantitative risk estimates in conjunction with other qualitative safety-related factors.

Agency Comments and Our Evaluation

We provided a draft of this report to NRC for review and comment. We received written comments from the agency's Executive Director for Operations. In its written comments, NRC generally addressed only those findings and recommendations with which it disagreed. Although commenting that it agreed with many of the report's findings, NRC expressed an overall concern that the report does not appropriately characterize or provide a balanced perspective on NRC's actions surrounding the discovery of the Davis-Besse reactor vessel head condition or NRC's actions to incorporate the lessons learned from that experience into its processes. Specifically, NRC stated that the report does not acknowledge that NRC must rely heavily on its licensees to provide it with complete and accurate information, as required by its regulations. NRC also expressed concern about the report's characterization of its use of risk estimates—specifically the report's statement that NRC's estimate of risk exceeded the risk levels generally accepted by the agency. In addition, NRC disagreed with two of our recommendations: (1) to develop specific guidance and a well-defined process for deciding on when to shut down a plant and (2) to develop a methodology to assess licensees' safety culture.

With respect to NRC's overall concern, we believe that the report accurately captures NRC's performance. Our draft report, in discussing NRC's regulatory and oversight role and responsibilities, stated that according to NRC, the completeness and accuracy of the information provided by licensees is an important aspect of the agency's oversight. To respond further to NRC's concern, we added a statement to the effect that licensees are required under NRC's regulations to provide the agency with complete and accurate information. While we do not want to diminish the importance of this responsibility on the part of the licensees, we believe that NRC also has a responsibility, in designing its oversight program, to implement management controls, including inspection and enforcement, to ensure that it has accurate information on and is sufficiently aware of plant conditions. In this respect, it was NRC's decision to rely on the premise that the information provided by FirstEnergy was complete and accurate. As we point out in the report, the degradation of the vessel head at Davis-Besse occurred over several years. NRC knew about several indications that problems were occurring at the plant, and the agency could have requested and obtained additional information about the vessel head condition.

We also believe that the report's characterization of NRC's use of risk estimates is accurate. The NRC risk estimate that we and our consultants found for the period leading up to the December 2001 decision on Davis-Besse's shutdown, including the risk estimate used by the staff during key briefings of NRC management, indicated that the estimate for core damage frequency was $5.4x10^{-5}$, as used in the report. The $5x10^{-6}$ referenced in NRC's December 2002 safety evaluation is for core damage probability, which equates to a core damage frequency of approximately $5x10^{-5}$—a level that is in excess of the level generally accepted by the agency. The impression of our consultants is that some confusion about the differences in these terms may exist among NRC staff.

Concerning NRC's disagreement with our recommendation to develop specific guidance for making plant shutdown decisions, NRC stated that its regulations, guidance, and processes are robust and do provide sufficient guidance in the vast majority of situations. The agency added that from time to time a unique situation may present itself wherein sufficient information may not exist or the information available may not be sufficiently clear to apply existing rules and regulations definitively. According to NRC, in these unique instances, the agency's most senior managers, after consultation with staff experts and given all of the information available at the time, decide whether to require a plant shutdown. While we agree that NRC has an array of guidance for making decisions, we continue to believe that NRC needs specific guidance and a well-defined process for deciding when to shut down a plant. As discussed in our report, the agency used its guidance for approving license change requests to make the decision on when to shut down Davis-Besse. Although NRC's array of guidance provides flexibility, we do not believe that it provides the structure, direction, and accountability needed for important decisions such as the one on Davis-Besse's shutdown.

In disagreeing with our recommendation concerning the need for a methodology to assess licensees' safety culture, NRC said that the Commission, to date, has specifically decided not to conduct direct evaluations or inspections of safety culture as a routine part of assessing licensee performance due to the subjective nature of such evaluations. According to NRC, as regulators, agency officials are not charged with managing licensees' facilities, and direct involvement with organizational structure and processes crosses over to a management function. We understand NRC's position that it is not charged with managing licensees' facilities, and we are not suggesting that NRC should prescribe or regulate the licensees' organizational structure or processes. Our recommendation is aimed at NRC monitoring trends in licensees' safety culture as an early warning of declining performance and safety problems. Such early warnings can help preclude NRC from assessing a licensee as being a good performer one day, and the next day being faced with a situation that it considers a potentially significant safety risk. As discussed in the report, considerable guidance is available on safety culture assessment, and other countries have established safety culture programs.

NRC's written response also contained technical comments, which we have incorporated into the report, as appropriate. (NRC's comments and our responses are presented in app. IV.)

As arranged with your staff, unless you publicly announce its contents earlier, we plan no further distribution of this report until 30 days from its issue date. At that time, we plan to provide copies of this report to the appropriate congressional committees; the Chairman, NRC; the Director, Office of Management and Budget; and other interested parties. We will also make copies available to others upon request. In addition, this report will be available at no charge on the GAO Web site at http://www.gao.gov. If you or your staff have any questions, please call me at (202) 512-3841. Key contributors to this report are listed in appendix V.

Jim Wells
Director, Natural Resources
and Environment

List of Congressional Requesters

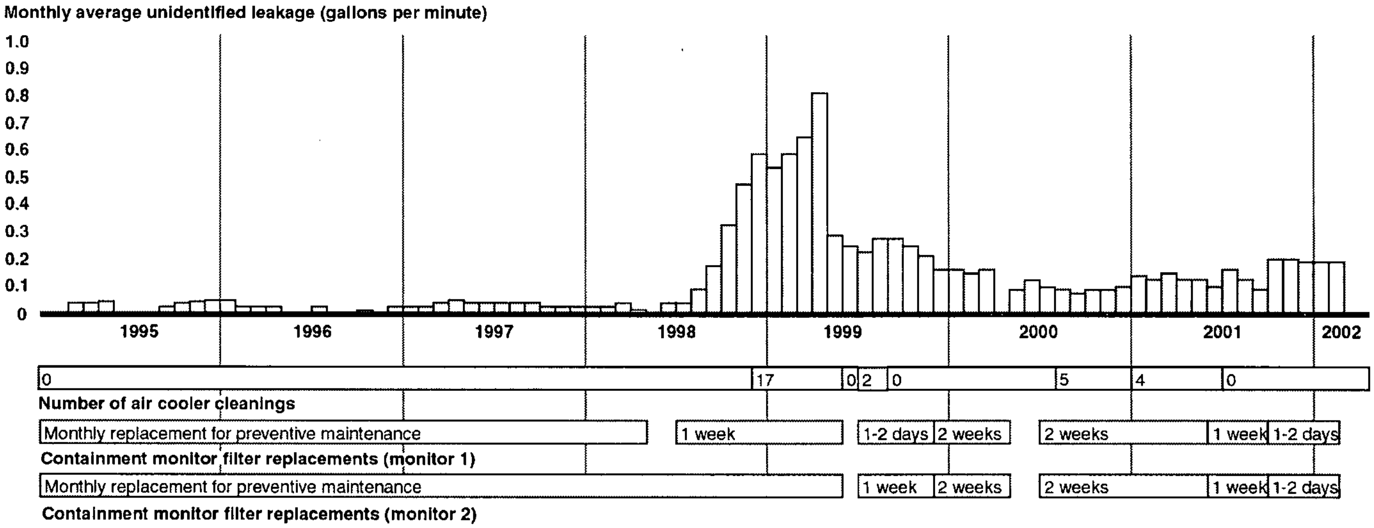
The Honorable George V. Voinovich
United States Senate

The Honorable Dennis J. Kucinich
House of Representatives

The Honorable Steven C. LaTourette
House of Representatives

Appendix I

Time Line Relating Significant Events of Interest



Source: GAO analysis of FirstEnergy, Electric Power Research Institute, and Dominion Engineering data.

Analysis of the Nuclear Regulatory Commission's Probabilistic Risk Assessment for Davis-Besse

Report of the Committee to Review the NRC's Oversight of the Davis-Besse Nuclear Power Station

John C. Lee
Department of Nuclear Engineering and Radiological Sciences
University of Michigan
Ann Arbor, MI 48109

Thomas H. Pigford
Department of Nuclear Engineering
University of California
Berkeley, CA 94720

Gary S. Was
Department of Nuclear Engineering and Radiological Sciences
University of Michigan
Ann Arbor, MI 48109

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Report of the Committee to Review the NRC's Oversight of the Davis-Besse Nuclear Power Station

1. Scope of the Review

The U. S. General Accounting Office formed a committee in September-October 2003 to review the oversight that the U. S. Nuclear Regulatory Commission provided on matters related to the pressure vessel head corrosion at the Davis-Besse (DB) Nuclear Power Station. The GAO charge to the committee was to respond to the questions:

(1) What probabilistic risk assessment model did NRC use and is it an appropriate model?
(2) What was the source of key data used to run NRC's probabilistic risk assessment and were these data valid?
(3) What key assumptions implicit in the model did NRC use to govern the estimated risk of different scenarios and were these reasonable?
(4) Is probabilistic risk assessment an appropriate tool for making such decision in these instances?
(5) How could NRC improve its use of probabilistic risk assessment to make more informed decisions?

The committee was initially provided with a set of 53 documents, which included GAO's preliminary analysis of the issues involved and chronology of the DB events during 2001 and 2002. The GAO reports summarized NRC-DB interactions in fall 2001 related to NRC Bulletin 2001-01 on control rod drive mechanism (CRDM) nozzle cracking, the eventual shutdown of the plant on 16 February 2002, and the subsequent discovery of pressure vessel head corrosion. Included also were:

(1) Official NRC documents, Generic Letters, Bulletins, and Information Notices transmitted to licensees including Davis-Besse,
(2) DB reports submitted to NRC related to the CRDM nozzle issues,
(3) NRC documents summarizing the staff's positions and discussions,
(4) Summaries of NRC staff presentations to NRC's Advisory Committee on Reactor Safeguards (ACRS) and to the Commission Technical Assistants,
(5) Event inquiry report of the NRC Office of Inspector General (OIG) and response from the NRC Chair,
(6) Redacted transcripts of OIG interviews of NRC staff, and
(7) Transcripts of GAO interviews with NRC staff.

The committee reviewed the initial set of documents received from GAO and conducted discussion on the phone and quite frequently via email. One member (GSW) provided a set of initial questions, which GAO used in a meeting with the NRC staff in October 2003. Another member (JCL) met with Mark Reinhart of NRC at the November American Nuclear Society meeting to discuss relevant technical issues and to prepare for a meeting of the review committee with NRC staff, which took place on December 11, 2003. At the meeting, two members (GSW, JCL) discussed technical and management issues with a total of nine NRC officials.

The review committee also consulted a number of experts from the industry and national laboratories, and reviewed a number of additional materials including:

(1) Several NRC Regulatory Guides,
(2) NRC Augmented Inspection Report and Lessons-Learned Task Force Report,

(3) Additional NRC reports on significance assessment of the DB CRDM degradations and the October 2003 OIG review of NRC's oversight on DB,
(4) Reports (including one proprietary version) from Electric Power Research Institute and Nuclear Energy Institute,
(5) Notes from William Shack, Argonne National Laboratory (ANL), describing his calculation of CRDM nozzle failure probability,
(6) DB probabilistic risk assessment (PRA) study performed for NRC by the Idaho National Engineering and Environmental Laboratory,
(7) Transcripts of several ACRS meetings during 2001–2003, and
(8) Select papers in engineering journals and proceedings.

The committee conducted an extensive review and discussion on the probabilistic risk calculations performed both by the FirstEnergy Nuclear Operating Company (FENOC) and NRC for Davis-Besse. One committee member (JCL) also developed a simplified analytical model to determine the CRDM failure probability, which provided a rough check on numerical calculations performed at ANL.

Following the 11 December 2003 meeting with the NRC staff, the committee made an effort to follow up on a number of questions that required additional information or clarifications. One essential piece of information is the core damage probability due to the postulated CRDM failure and ejection that NRC actually used in connection with the decision to allow continued DB operation until February 16, 2002. After a long wait, finally on February 24, 2004, the committee received a response from Jin Chung, Richard Barrett, and Gary Holahan, summarizing, to the extent they could reconstruct, how NRC arrived at key quantitative risk estimates in November 2001.

We present in Section 2 key findings of the committee on NRC's oversight related to the DB issues. We provide responses to the first four GAO charges in Sections 3 through 6, in a slightly restructured format, covering (a) PRA methodology and data used in NRC's risk assessment, (b) assumptions and uncertainties in the risk assessment, (c) relevant regulations and guidelines, and (d) November 2001 NRC decision. Our response to the fifth GAO charge is finally presented in Section 7.

2. Key Findings of the Committee

The committee presents key findings of its review on NRC's oversight on Davis-Besse and related safety and regulatory issues:

(1) <u>NRC's Risk Analysis for Davis-Besse</u>

(a) To guide a risk-informed decision on whether to grant an extension beyond its December 31, 2001 date for shutdown of Davis-Besse for nozzle inspection, NRC relied on its PRA of risks from crack-induced failure of control-rod housing nozzles. The calculated risk was incorrectly small because the calculations did not consider corrosion of the reactor vessel due to boric acid in coolant leaking through the cracks. The calculated risk was also subject to large uncertainties. As a result, NRC staff found it difficult to balance results of quantitative risk calculations against qualitative considerations. Regulatory Guide 1.174 provided little help in this regard.

(b) NRC did not perform uncertainty analysis in applying PRA in the DB decision-making process and there was confusion regarding the interpretation of core damage frequency (CDF) and core damage probability (CDP) as risk attributes within the framework of RG 1.174. NRC staff should have recognized large uncertainties associated with the CDF estimated for CRDM nozzle failures

(c) NRC's risk analysis was poorly documented and inadequately understood by NRC staff.

(d) Even now, NRC is unable to provide estimates of the risk from continued operation of Davis-Besse from December 31, 2001 to February 16, 2002, taking into account the large corrosion cavity in the reactor vessel head found in March 2002. The risks from that operation prior to shutdown are likely to have been unacceptably large. Thus, with proper risk analysis, quantified risk calculations would have provided clear guidance for prompt shutdown.

(2) <u>Relevant Regulations and Guidelines</u>

(a) Coolant leakage through flanges and valves was allowed under the DB Technical Specifications, leading the DB personnel and NRC resident inspectors to treat boric acid deposits in various locations in the containment as routine events, and hence not risk significant.

(b) NRC has no predetermined methodology to weigh PRA against deterministic factors. NRC needs to develop a set of guidelines for the use of PRA in decision-making.

(3) <u>November 2001 Davis-Besse Decision</u>

(a) The proposed shutdown date of 31 December 2001 was arbitrary. There was significant pressure from DB to delay the shutdown for financial reasons, but no cost-benefit analysis was presented.

(b) Communication was seriously lacking between NRC headquarters and Region III and also between resident inspectors and Region III administrators regarding the extent of coolant leakage and boric-acid corrosion.

(c) NRC staff incorrectly assumed that the visible white deposits of anhydrous boric acid resulted entirely from rapid evaporation and drying of the leaking coolant and were not associated with corrosion.

(d) The transparency of the decision-making process within NRC is not uniform. The NRC lacks an established and well-defined process for decision-making.

(4) <u>General Safety and Regulatory Issues</u>

(a) How to ensure safety from corrosion by leaking coolant is generic to all pressurized water reactors (PWRs). There is no evidence that it has been evaluated as such by NRC's Advisory Committee on Reactor Safeguards.

(b) The root cause of this near miss of a serious accident at Davis-Besse is human error: inadequate evaluation of the effect of simplifying assumptions in the risk analysis and inadequate perception and understanding of the many clues that challenged those assumptions.

(c) NRC is slow to integrate new safety information into its programs, and to share that information with its licensees.

3. NRC Probabilistic Risk Assessment Model and Database

3.1 Basic PRA Methodology and Data Used for the DB Risk Analysis

The NRC staff relied on a Standardized Plant Analysis Risk (SPAR) study [Sat00] for Davis-Besse that Idaho National Engineering and Environmental Laboratory performed. The Saphire code [Sap98] provided the PRA tools and database for key system failure rates and human error probabilities in the SPAR study. The PRA methodology combines semi-pictorial structures of event and fault trees to estimate the probability of occurrence of rare events, in particular, the core damage frequency (CDF) and large early release frequency (LERF) of radioactivity associated with the operation of a nuclear power plant. An event tree is constructed for each major sequence of events beginning with an initiating event, e.g., a medium-break loss-of-coolant accident (MBLOCA), and following through multiple stages of safety systems to be activated. The probability of failure or unreliability of a safety system that is called upon to function is determined as the probability of the top event of a fault tree, which is determined through Boolean logic representing failure probabilities of components making up the top event. Uncertainties in the CDF and LERF are then obtained by a Monte Carlo convolution of probability density functions representing failure rates of components in fault trees and of safety systems in event trees.

The MBLOCA, which is assumed to occur following the failure and ejection of CRDM nozzles at Davis-Besse, is analyzed in the SPAR report [Sat00] as one of 12 major internal events postulated to lead to core damage and radioactivity release. A baseline CDF of 1.0×10^{-7}/year for MBLOCA results from a generic value [Pol99] of the initiating event frequency of 4.0×10^{-5}/year for the MBLOCA combined with the failure probabilities of a number of engineered safety features, including high- and low-pressure injection systems. This results in an estimate of 2.5×10^{-3} for the conditional core damage probability (CCDP) for MBLOCA. The CCDP of 2.5×10^{-3} is almost entirely due to the failure of low-pressure recirculation pumps, which in turn depends heavily on the ability of the operator to properly align and start the pumps. Based on human factor analysis, an estimate of 1.0×10^{-3} for the operator error is included in determining the CCDP of 2.5×10^{-3}. The baseline or point-estimate CDF of 1.0×10^{-7}/year for MBLOCA contributes 0.5% toward the total baseline CDF of 2.0×10^{-5}/year, with uncertainties represented as CDF = {5th percentile, median, mean, 95th percentile | 6.3×10^{-6}, 1.6×10^{-5}, 5.1×10^{-5}, 9.6×10^{-5}} per year. The SPAR report for Davis-Besse provides only baseline CDF estimates for individual core damage events; hence no uncertainty estimates are available for the MBLOCA event. The mean overall CDF = 5.1×10^{-5}/year for Davis-Besse compares well with the those for internal initiating events for three PWR plants analyzed extensively as part of NRC's severe accident evaluation project in NUREG-1150 [Nrc90]: Surry Unit 1, 4×10^{-5}/year; Sequoyah Unit 1, 6×10^{-5}/year; and Zion Unit 1, 6×10^{-5}/year. The CDF estimates for the four PWRs are, however, an order of magnitude larger than those for two boiling water reactors analyzed in NUREG-1150: Peach Bottom Unit 2, 5×10^{-6}/year, and Grand Gulf Unit 1, 4×10^{-6}/year.

3.2 DB Calculation of Risk due to CRDM Nozzle Failures

The DB calculation of the nozzle failure probability consisted of the following steps [Cam01c]. The nozzles were divided into three groups based on the extent of visual inspection possible during refueling outage (RFO) 10, 11 and 12. Group 1 consisted of 15 nozzles that were not inspected during RFO 10 and 11. Group 2 consisted of 5 additional nozzles that were not inspected during RFO 12. Group 3 consisted of 45 nozzles, all of which were inspected during all outages. This analysis accounts for 65 nozzles, four short of the total number of nozzles on the DB head. The four nozzles not

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included in this analysis are at the center of the head. They were determined by a Structural Integrity Associates analysis [Cam01d] to have no demonstrable annular gaps, and therefore, were considered as not susceptible to circumferential cracking and were excluded from the calculation. This particular assumption turned out to be quite inappropriate, since the February-March 2002 inspection revealed that three central nozzles (Nos. 1, 2, 3) had developed through-wall axial cracks and that nozzle 2 also had a circumferential crack.

Leak frequencies were determined for each group according to the equation: leak frequency = 1.1/year × F_i, where F_i is the fraction of the total nozzles (65) in group i, and the value of 1.1 is the estimated frequency of CRDM leaks per reactor year based on observations on 5 other Babcock and Wilcox (B&W) plants. Data on CRDM cracking noted in the 2001-01 NRC Bulletin were incorporated into the PRA analysis [Cam01c] in calculating the leak frequency. Specifically, recent inspections had revealed that there were sixteen leaking nozzles identified in the B&W plants, Arkansas Nuclear One Unit 1 (ANO-1), Crystal River Unit 3 (CR-3), Oconee Nuclear Station Unit 1 (ONS-1), ONS-2 and ONS-3. The assumption was made that all leaks appeared during the most recent two fuel cycles. Assuming 1.5 years per fuel cycle, 2 cycles per plant and 5 plants, a product of these three values yields 15 reactor years of operation. Sixteen leaking nozzles over 15 years of operation yields a leak frequency of about 1.1 leaks per reactor year. This value then incorporated the most recent data on CRDM cracking at other B&W plants.

An event tree was constructed for each CRDM group, beginning with the CRDM leak frequency, accounting for crack growths and failures during subsequent operation and CRDM nozzle inspection failures, and culminating with a total CDF. The event tree analysis included CCDP = 2.7×10^{-3} for all groups. The resulting total CDF summed over all three groups was 6.97×10^{-6}/year. Dividing by the CCDP yielded a value of the initiating event (IE) frequency of 2.58×10^{-3}/year representing an MBLOCA due to CRDM nozzle ejection. Using the IE frequency, one would then calculate an IE probability of 3.4×10^{-4} for continued DB operation for another 0.13 year, representing the period between 31 December 2001 and 16 February 2002. We note here also that the DB estimation of CCDP = 2.7×10^{-3} agrees closely with the SPAR estimate of 2.5×10^{-3} discussed in Section 3.1.

The probability of missing a leak in an inspection was estimated by Framatome [Cam01b] using human reliability analysis. Their estimates [Cam01d] indicated that the probability of missing a leak was 0.06 in the first inspection (RFO 10), 0.065 in the second inspection (RFO 11) and 0.11 in subsequent inspections. Davis-Besse's analysis [Cam01c], however, uses a single probability of value 0.05 applied to all of the nozzles covered in RFO 10, 11 and in subsequent inspections. The document [Cam01c] references the Framatome analysis [cam01b], but does not indicate why a different value was used and why a single, lower value was applied for all inspections. Correcting, however, the calculation to account for the three separate failure detection probabilities results in an IE frequency of 2.64×10^{-3}/year vs. 2.58×10^{-3}/year assumed [Cam01c].

3.3 NRC Calculation of Risk due to CRDM Nozzle Failures

Although documents provided to the review committee do not provide sufficient details on how NRC arrived at the incremental CDF or core damage probability (CDP), it appears that the NRC staff used the DB estimate of CCDP = 2.7×10^{-3} for the MBLOCA initiated by CRDM nozzle failure and ejection. The NRC did not have the in-house expertise to determine the nozzle ejection probability for Davis-Bessie. They had two sources for estimates of the nozzle ejection probability. One source was Dr. William Shack at Argonne National Laboratory (ANL). Dr. Shack conducted a rather extensive analysis of the failure probability consisting of 5 steps: 1) the number of cracked nozzles, 2) the crack size distribution, 3) the crack growth rate, 4) a time to failure based on initial crack size and crack growth rate, and 5) a probability of failure, based on a Monte Carlo analysis of failure times. The end result was a plot and a table with failure probability vs. time that was provided to NRC and is described in several references [Sha01, Sha03, Nrc01a]. The second source of information on the MBLOCA frequency was the DB estimate [Cam01c] for IE frequency of 2.58×10^{-3}/year, discussed in Section 3.2.

Documents provided to the review committee [Rei03, Chu04] list the IE probability of 2.0×10^{-3} for continued operation for another 0.13 year, representing the period between 31 December 2001 and 16 February 2002, but reference Dr. Shack as the source. However, the values provided by Shack to the NRC [Sha01] do not agree with this number and apparently NRC decided not to use the ANL analysis, as it was viewed as preliminary, and a work in progress.

In a final response [Chu04] to questions the review committee raised following the 11 December 2003 meeting with nine NRC staff, Jin Chung, Richard Barrett, and Gary Holahan confirmed that NRC used the DB estimate of CCDP = 2.7×10^{-3}, coupled with the IE frequency of 2.0×10^{-2}/year, to obtain an incremental CDF = 5.4×10^{-5}/year, associated with the postulated CRDM failure and ejection leading to an MBLOCA. They indicate that, instead of allowing for the inspection failure probability of 0.05 for RFO 10, assumed in the Framatome risk calculation [Cam01c], NRC allowed no credit to discover the nozzle cracking. NRC, however, used the same crack growth and failure rates as in the Framatome PRA submittal to arrive at the IE frequency of 3.4×10^{-2}/year, which is an order of magnitude larger than the Framatome estimate of 2.58×10^{-3}/year. Dr. Chung then decided to reduce the IE frequency to 2.0×10^{-2}/year to "reflect best estimate rather than 75 percentile fracture mechanics," which is the best description of the adjustment that NRC is able to present in February 2004. The adjusted value of IE frequency = 2.0×10^{-2}/year is then used together with CCDP = 2.7×10^{-3} to yield the incremental CDF = 5.4×10^{-5}/year. Finally, to convert the incremental CDF to an incremental CDP, associated with the continued DB operation for 0.13 year, NRC again rounded off the resulting CDP = 7.0×10^{-6} to 5.0×10^{-6}. In the deliberations leading to the 28 November 2001 DB decision, NRC apparently used the adjusted, rounded-off risk estimates: incremental CDF = 5.4×10^{-5}/year and incremental CDP = 5.0×10^{-6}.

The conclusion of the review committee is that the determination of IE probability is questionable, and that the error or uncertainty associated with this probability is likely to be very high, rendering it of questionable value. In the February 2004 response [Chu04] to the review committee questions, NRC confirms that no uncertainty analysis was performed on the incremental CDF and CDP estimates they used in November 2001. Furthermore, NRC proposes an unusual use of the incremental CDF and CDP values to compare with the quantitative guidelines given in RG 1.174 [Nrc02a]. This will be discussed further in Section 5.1.

4. Assumptions and Uncertainties in NRC Risk Analysis

4.1 The Discovery of Massive Corrosion Wastage at Davis-Besse

The most serious shortcoming in NRC's risk analysis was the complete neglect of any consideration of corrosion of the reactor vessel by boric acid in reactor coolant known to be leaking from the high-pressure cooling system. After finally shutting down the reactor and inspecting the control housing nozzles, Davis-Besse discovered extensive corrosive wastage of the steel pressure vessel. Boric acid in leaking coolant had reacted with iron to form a mass of corrosion products which, when removed, left a cavity the size of a pineapple. Corrosion had penetrated the 6-inch thick steel head of the reactor vessel and exposed the thin corrosion-resistant vessel liner, found to be only about 0.2 inches thick at that location.

The reactor had been operating for months, maybe years, perilously close to rupture of the vessel liner and rapid loss of reactor coolant. In response to our repeated requests to NRC to share with us what it has learned about the risks from corrosion-induced failure of the coolant pressure boundary, NRC states that such analysis has not been completed, awaiting completion of laboratory tests on relevant failure mechanics at the Oak Ridge National Laboratory. That answer is most disappointing.

An earmark of a responsive safety program is prompt incorporation of new safety information, by undertaking new risk analysis, whether deterministic, probabilistic, or both, to guide new procedures that would avoid such a potential accident and to guide research and testing necessary for proper risk-informed decision making. Now, some two years since the discovery of massive and dangerous corrosion wastage at Davis-Besse, NRC seems unable to supply even preliminary analysis of the magnitude of potential safety problems arising from coolant leakage and corrosion. This harks back to the 1977-79 era, when NRC failed to recognize the implications of a near miss of a serious reactor accident at Davis-Besse, discussed further in Section 6.6. If NRC had made a prompt analysis of Davis-Besse's 1977 operator errors and the implications for a more serious accident if not corrected, and if that analysis had been communicated to other licensees, the tragic accident at Three Mile Island could have been avoided. It appears that NRC has not fully recovered from its mistakes in 1977-79.

4.2 Assumption that Boric Acid in Hot Escaping Coolant Will Not Corrode

Apparently all NRC staff who were involved in the November 2001 decision on Davis-Besse were aware that high-pressure coolant was leaking from valves, flanges, and possibly from cracks, but they evidently thought that the hot coolant, at 600 °F, would immediately flash into steam and non-corrosive anhydrous compounds of boric acid. As evidence, they referred to the readily visible deposits of white fluffy anhydrous boric acid observed on plant equipment. But evaporation concentrates boric acid in the remaining liquid, which becomes far more corrosive. Its vapor pressure decreases and slows further evaporation. Thus, one should expect that some of the boric acid in the escaping coolant can reach the metal surfaces as wet or moist highly corrosive material underlying the white fluffy surface layers. That is evidently what happened. It should have been anticipated.

Also the geometry of a cracked nozzle was not considered in NRC's thoughts about boric acid corrosion. NRC was focused on the metal surface because they were convinced that the boric acid they saw came from "dripping" from the leaky valves above the head. However, in a leaking nozzle, the escape path of the water is some 6-8 inches – from the clad to the vessel surface. Such a long crevice provides considerably greater opportunity for concentration of the liquid behind the evaporation front at or near the vessel head surface where the steam escapes.

NRC staff should also have been aware of experience at the French nuclear plants, where boric acid corrosion from leaking reactor coolant had been identified during the previous decade, the safety significance had been recognized, and safety procedures to mitigate the problem had been implemented. Keeping abreast of safety issues at similar plants, whether domestic or abroad, and conveying relevant safety information to its licensees is an important function of NRC's safety program.

NRC staff were involved a few years earlier in discussions regarding boric acid deposits on the reactor pressure vessel head [Epr01]. Boric-acid corrosion programs were initiated. But to the NRC staff involved in the November 2001 decision on Davis-Besse, boric-acid corrosion was not viewed as a significant safety concern; rather, there was concern that the anhydrous crystals could obscure indication of leakage from the nozzles above the reactor head. But already several tests of boric acid corrosion had been underway in industry and government laboratories. Representative tests of nozzle leakage showed that corrosion rates from boric acid solutions dripping onto carbon steel at 600 °F can be in the range of four inches per year [Nrc02b]. Drip tests sponsored by the Electric Power Research Institute [Sri98, Epr01] showed that the corrosion rate is much higher for carbon-steel surfaces at 600 °F than at lower temperature. Only at temperatures much higher than 600 °F is the vaporization rate high enough to produce anhydrous boric acid crystals with little corrosion.

NRC personnel involved in the November 2001 safety review evidently were not aware of these corrosion tests or else they had forgotten about them. An NRC resident inspector at Davis-Besse was shown, by a Davis-Besse engineer, a photograph that revealed streaks of rust-colored corrosion products on the head of the reactor vessel, in the midst of the expected white crystals. But the inspector was not aware of the significance of these rust streaks, and he did not report this information to other NRC personnel. At other times, Davis-Besse reported the presence of airborne rust particles that had lodged on the surveillance filters, but the significance of this information was not recognized.

After the discovery of the corrosion wastage in 2002, an NRC official was asked about the corrosion data reported by the Electric Power Research Institute (EPRI). He replied that those data were not considered in the discussions with Davis-Besse because EPRI had not "submitted" the report of those data to NRC. EPRI points out that the corrosion data had been published in 1998 in a widely available technical report, well known to industry and NRC. EPRI had not formally "submitted" the report because NRC charges a fee for the submittal process.

4.3 Control Rod Ejection and Reactivity Transient

In discussions related to the consequences of CRDM nozzle ejections at Davis-Besse, NRC duly considered the effects of the control rods ejected, thereby made inoperable, in the resulting LOCA. They apparently concluded before the 28 November 2001 Davis-Besse decision that the negative reactivity feedback resulting from the overheating and boiling of coolant in a LOCA would easily overshadow any potential decrease in the amount of subcritical reactivity that would ensure safe shutdown of the reactor. Furthermore, a more recent NRC report [Dye03] evaluating the significance of the Davis-Besse CRDM penetration cracking and pressure vessel head degradation presents a similar conclusion. Here, a combined thermal-hydraulic and reactivity transient analysis performed with the RELAP code indicates that the boiling of the reactor coolant coupled with the addition of boric acid in the emergency coolant water injected is sufficient to maintain the shutdown condition, thereby obviating the concern for an anticipated transient without scram (ATWS).

One consequence of the CRDM nozzle ejection that has not been, however, analyzed is the positive reactivity inserted into the reactor core when the control rod ejection occurs in a hot zero power (HZP) rather than a hot full power (HFP) condition. The consequences of postulated control rod ejection accidents are generally more severe, if initiated in a HZP condition when the system is fully pressurized but at low power. This is because at HZP the control rods would be inserted deeply into the core, thereby adding

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a larger positive reactivity when the rods are ejected, than that resulting in a HFP rod ejection accident. Thus, a HZP CRDM nozzle ejection could result in a power level above rated power before a significant coolant heating or boiling occurs. This combination of postulated accidents requires an integrated analysis of two PWR design basis accidents, LOCA and rod ejection accident, and should be performed for a complete evaluation of CRDM nozzle ejection consequences.

4.4 Need to Account for Corrosion in Risk Analysis

NRC's analysis of risks from nozzle cracking was concerned only with the formation and propagation of circumferential cracks that could result in nozzle failure, loss of coolant, and even control rod ejection. The formation of axial cracks was neglected in the risk analysis. There is less chance of axial cracks causing complete failure of a nozzle but they do open additional pathways for coolant leakage. Leakage from axial cracks is believed to have been the main source for the massive corrosion wastage at Davis-Besse.

Neglecting axial cracking and corrosion wastage that could result in rupture of the reactor vessel and a more serious loss-of-coolant accident was a principal deficiency in NRC's risk assessment.

NRC has not described to us any plans for extensions to its risk analysis that would predict the dangers of corrosion wastage. In our view, the necessary additional ingredients of the probabilistic risk analysis must include:

- Formation and growth of axial cracks in control-rod-housing nozzles,
- Flow of leaking coolant from cracks,
- Evaporation of leaking coolant and concentration of boric acid,
- Corrosion of the steel pressure vessel,
- Time-dependent penetration of the corrosion front into the pressure vessel,
- Corrosion and stress-corrosion cracking of the vessel liner,
- Time-dependent calculation of stress on the vessel and its failure if ruptured, and
- Loss-of-coolant analysis of reactor core damage if rupture occurs.

Some of the possible parameters for such an analysis were developed for this report from sources other than NRC, as outlined in the next section. The wide variations in some of the key parameters illustrate uncertainties that must be resolved to make accurate predictions of risk and its uncertainty.

4.5 Uncertainties in Predicting Risks from Nozzle Cracking

For risk-informed decision making, it is important to include calculation of uncertainties in the predicted risks. NRC informs us that it has not calculated uncertainties in its present risk assessments of nozzle cracking. It does believe that its present results on core-damage risks are accurate "to within a factor of 2 or 3". NRC did not provide the basis for their belief. The information necessary for probabilistic risk calculation should include enough data for uncertainty analysis. NRC should perform uncertainty calculations.

A major uncertainty arises in attempting to predict the corrosion wastage that would rupture the reactor vessel, particularly after boric-acid-induced corrosion has penetrated all the way through the carbon steel and exposed the thin stainless steel liner that would serve as the reactor coolant system pressure boundary, as occurred at Davis-Besse. From other sources [Pin03a,b], we are informed that in early 2003 an internal NRC memo concluded that there was no danger of imminent rupture of the Davis-Besse reactor prior

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to its shutdown in February 2002. The memo cited calculations by the Oak Ridge National Laboratory that the as-discovered cavity could have supported twice the operating pressure of 2185 psia before rupturing and that, "had the cavity enlarged under continued operation, at least twelve months remained before the cavity would reach a size that rupture would occur at normal operating temperature and pressure." It was assumed that "the wastage cavity was actively growing at a maximum rate of seven inches per year" [Pin03a], much greater than the 4 inches per year quoted earlier by NRC. The NRC memo stated that the need for more accurate data on the morphology and depth of cladding cracks necessitates a revision of these calculations and expects a possible reduction in the amount of margin that was originally calculated.

A report by Structural Integrity Associates [Sia02], commissioned by FirstEnergy, calculated that the cladding could withstand pressures of more than 5000 psia. Davis-Besse concluded that vessel rupture "was therefore considered not to be a credible event". Later in 2003, an Oak Ridge National Laboratory study, conducted on a spare reactor-vessel head with a machined-out cavity simulating wastage, reported two rupture tests, one occurring at 2000 psia, the other at 2700 psia. If these two results are applicable, Davis-Besse had been operating at 2185 psia with significant probability of vessel rupture. NRC's project manager for these tests stated in October 2003 that the Oak Ridge test results would be made public "probably within weeks." The report is not yet released.

An important feature of the Oak Ridge tests was taking into account the "dissimilar weld" between the carbon-steel vessel head and the stainless steel cladding. The Union of Concerned Scientists pointed out that the Oak Ridge tests revealed that the weld overlay process used for the Davis-Besse vessel left a thin interface that was not as strong as either of the adjoining layers. Also, the tests were conducted quasi-statically, whereas pressure transients during reactor operation must be considered [Pin03b].

These are examples of crucial data uncertainties that need to be resolved. Such uncertainties must be considered in reporting probabilistic risks.

It is not enough to finesse such uncertainties by instituting new procedures intended to eliminate the possibility of operator error. The near accident at Davis-Besse resulted from human error, errors by reactor operators, by NRC on-site inspectors and by the staffs at Davis-Besse and NRC. The experience at Three Mile Island has taught us that human errors can occur and must be included in responsible risk analysis.

4.6 Lack of Uncertainty Analysis in DB Risk Estimation

As discussed in Section 4.5, an important issue regarding the application of quantitative guidelines for risk management and regulatory decisions, as in the Davis-Besse case under review, is the need to account for uncertainties in risk values determined through PRA techniques. It was noted in Sections 3.1 and 3.3 that we are unable to obtain any uncertainty estimates for the SPAR baseline CDF of 1.0×10^{-7}/year for Davis-Besse MBLOCA, without CRDM nozzle failures, or the NRC estimate of 5.4×10^{-5}/year for the corresponding MBLOCA CDF accounting for CRDM nozzle failures. It is well known among the PRA community that all quantitative risk estimates for nuclear power plants are subject to significant uncertainties and that it is imperative that proper uncertainty analysis be performed for any PRA study for nuclear power plants. This point was made abundantly clear in a recent NRC report [Fle03], prepared at the request of NRC's Advisory Committee on Reactor Safeguards (ACRS), for the purpose of evaluating practices and issues regarding PRA applications. The need to understand and characterize uncertainties in PRA and risk-informed regulatory activities was also emphasized in both RG 1.174 [Nrc02a] and RG 1.200 [Nrc03]. Furthermore, it was primarily for the purpose of duly accounting for uncertainties in the calculated risks of postulated severe accidents that NRC and its contractors had to go through two draft versions of the massive volumes of the severe accidents risk study of NUREG-1150 [Nrc90] before releasing the final version in 1990. Nonetheless, it is rather clear to the review committee that the NRC staff and management did not give due considerations to the impact of large uncertainties, in particular, in the frequency of MBLOCA initiated by the postulated Davis-Besse CRDM nozzle ejection in their Davis-Besse deliberations in November 2001. In addition, the SPAR calculation of CCDP = 2.5×10^{-3} is subject to significant uncertainties associated with human errors and common cause failures represented in the fault tree analysis. Questions were also raised in GAO interviews with the NRC staff if the staff had the proper understanding of the impact on the CCDP estimate of the compensatory measures proposed by Davis-Besse before the November 2001 decision.

During the 11 December 2003 meeting with the NRC staff, we got the indication that several NRC staff felt that Regulatory Guide 1.174 [Nrc02a], with its PRA framework, does account for uncertainties in risk estimates including the effects of unknown events, e.g., the Davis-Besse pressure vessel head wastage, through the defense-in-depth philosophy. As discussed in detail in the February 2003 NRC Region III report [Dye03], it is very much doubtful how the system modeling uncertainties and unknown events could possibly have been represented through a simple application of RG 1.174. It is noteworthy that the ACRS, at its first full committee meeting [Acr02] after the Davis-Besse cavity findings, repeatedly criticized the NRC staff for not having performed any uncertainty analysis for the CRDM nozzle failure issues and suggested that the staff had drifted away from the RG 1.174 guidelines. Had the staff gone through even a simple analysis, without any detailed uncertainty calculations or invoking RG 1.174, they should have realized that the *incremental* CDF of 5.4×10^{-5}/year would result in doubling the total CDF for Davis-Besse, even with the mean SPAR value of 5.1×10^{-5}/year. Note furthermore that the SPAR baseline CDF is 1.6×10^{-5}/year. Thus, the staff should have readily recognized the risk significance of the incremental CDF = 5.4×10^{-5}/year estimated in November 2001 for the CRDM nozzle failure event.

One regulatory decision-making case where PRA applications were questioned is the ATWS issue. A recent review [Rau03] emphasizes that the uncertainty in the calculated values of the reactor scram system reliability requires maintaining defense in depth regarding ATWS, rather than relying heavily on PRA results. Thus, despite small values of scram failure probabilities calculated in the early 1980s, system changes, including improved reactor shutdown systems and circuits, were implemented but only after incipient ATWS events had occurred at the Salem Unit 1 plant in 1983 [Sci83]. We suggest that the NRC staff should have applied the lessons learned from the ATWS rulemaking case to the DB case, which would have reduced the NRC staff's heavy reliance on the quantitative risk. Although we will never be able to determine the extent by which the incremental CDF or CDP values influenced the decision making, it is rather apparent to the review committee that the quantitative risk values, without due considerations for uncertainties, did play an important role in the 28 November 2001 decision.

5. Relevant Regulations and Guidelines

5.1 Use of Regulatory Guide 1.174 and Other Guidelines in the DB Decision

One key set of guidelines discussed extensively among the NRC staff and management before the 28 November 2001 DB decision is RG 1.174 [Nrc02a], which is intended to promote risk-informed decisions on plant-specific changes. Included in RG 1.174 is one particular quantitative metric in the form of incremental CDF. According to Figure 3 illustrating acceptance guidelines, any plant-specific changes resulting in an incremental CDF of 1×10^{-5}/year or higher should not be allowed. In addition, there apparently was considerable discussion and lack of unanimity among the NRC staff prior to the 28 November 2001 decision if the other four safety principles of RG 1.174 were satisfied. The February 2003 NRC Region III report [Dye03] documenting the significance of the Davis-Besse CRDM penetration cracking and pressure vessel head degradation leaves, however, no question that all five safety principles of REG 1.174 were violated at Davis-Besse in November 2001. Included in this report is a revised estimate of incremental MBLOCA frequency of 3.0×10^{-2}/year, yielding estimates of incremental CDF in the range of [1×10^{-5}, 1×10^{-4}] per year, due to the ejection of three central CRDM nozzles. These estimates of incremental CDF bracket the value of 5.4×10^{-5}/year presented to the review committee [Rei03] and would have clearly resulted in violation of the sole quantitative metric of RG 1.174.

Although the February 2003 findings of NRC rendering Davis-Besse in the "red" status are attained certainly with the benefits of hindsight, it is worth summarizing the reasoning presented in the report, rather than presenting the review committee's evaluations:

(1) Principle 1: *Regulations were not met*, because reactor coolant system (RCS) pressure boundary leakage occurred over an extended period of time and the RCS was not inspected and maintained properly. This resulted in violation of the General Design Criteria.
(2) Principle 2: Performance and maintenance deficiency *degraded the level of defense in depth* required for safe operation of the plant.
(3) Principle 3: *Safety margins were not maintained* because the integrity of the RCS pressure boundary relied solely on the vessel lining, which was not designed for this purpose.
(4) Principle 4: *Calculated risk violated the quantitative guideline.*
(5) Principle 5: There was *no basis for assuring that degradations* due to CRDM leaks *would be properly monitored and managed.*

It goes without saying that nobody anticipated in November 2001 the severe vessel wastage that was uncovered in March 2002, which resulted in an unambiguous verdict regarding Principle 3 above. Nonetheless, there were sufficient indications in November 2001 to question if safety margins were not violated, as voiced by a number of the NRC staff before the 28 November 2001 decision. This in turn raises questions if NRC made proper application of RG 1.174 in arriving at the decision to allow a delay of the shutdown of Davis-Besse for the pressure vessel head inspection required in NRC Bulletin 2001-01 [Nrc01c].

During the 11 December 2003 meeting with the NRC staff, the review committee was offered a number of other NRC and industry guidelines that the NRC staff apparently used for the Davis-Besse decision. A review of these additional guidelines further suggests that the NRC value for the incremental CDF = 5.4×10^{-5}/year for seven weeks of additional Davis-Besse operation could not have satisfied these guidelines either. To clarify the point here, we follow the process NRC used to convert the incremental CDF = 5.4×10^{-5}/year to the incremental core damage probability (CDP) for seven weeks or 0.13 year: incremental CDP = 5.4×10^{-5}/year x 0.13 year = 7.0×10^{-6}, rounded off to 5.0×10^{-6}, which is roughly equivalent to approximating 7 weeks as 0.1 year. We may now compare this incremental CDP estimate with three additional guidelines for risk-informed decision-making processes:

(1) RG 1.177 [Nrc98] intended for evaluating Technical Specification changes suggests that an incremental CDP of 5×10^{-7} is acceptable for relaxation of allowed outage time or surveillance test intervals.
(2) PSA Applications Guidelines [Tru95] proposed by the Electric Power Research Institute indicates that an incremental CDP in the range of [1×10^{-6}, 1×10^{-5}] requires assessment of non-quantifiable factors.
(3) NUMARC 93-01 [Nei96] suggests that an incremental CDP in the range of [1×10^{-6}, 1×10^{-5}] requires risk management actions, adding further that any decisions resulting in an incremental CDP greater than 1×10^{-5} should not be allowed.

Thus, NRC's incremental CDP value of 5×10^{-6} would have resulted in violation of RG 1.177 and would have required risk management actions according to both the EPRI and Nuclear Energy Institute guidelines. In addition, during the 11 December 2003 meeting with the NRC staff, Richard Barrett insisted that the quantitative RG 1.174 guidelines are supposed to be applied in terms of incremental CDP, not incremental CDF as stipulated clearly in the Regulatory Guide. In the February 2004 response [Chu04] to the review committee questions, NRC now proposes that the incremental CDF used as a key metric in RG 1.174 is meant to be an annual average. Thus, NRC now suggests that the incremental CDF = 5.4×10^{-5}/year for 13% of a year should be combined with CDF = 0.0 for the remaining 87% of the year to yield an annual-average incremental CDF = 5×10^{-6}/year. This new interpretation is at best unusual and certainly is inconsistent with clear RG 1.174 guidelines regarding the use of incremental CDF. This reinforces the impression of the review committee that perhaps there was in November 2001 and possibly is still some confusion among the NRC staff regarding basic quantitative metrics that should be considered in evaluating regulatory and safety issues.

A recent release of RG 1.200 [Nrc03] is intended to provide guidance for determining the technical adequacy of PRA results in regulatory decision making. The Regulatory Guide discusses various technical characteristics and attributes that should be included in PRA, and highlights the importance of capturing system dependencies in risk evaluations. RG 1.200 also emphasizes that understanding uncertainties in PRA is an essential aspect of risk characterization and refers to RG 1.174 for guidance on how to address the uncertainties. As reviewed in connection with the DB decision-making process, however, we feel that the guidelines in RG 1.174 are not specific enough, especially for PRA results subject to large uncertainties and for representing events not well understood.

5.2 Technical Specifications and General Design Criteria Regarding Coolant Leak

Davis-Besse technical specification 3.4.6.2 requires that no reactor coolant pressure boundary (RCPB) leakage is allowed. The General Design Criteria, 10 CFR 50 Appendix A, addresses reactor coolant pressure boundary leakage in GDC 14, GDC 31, and GDC 32. GDC 14 specifies that the RCPB have an extremely low probability of abnormal leakage, or rapidly propagating failure, and of gross rupture. GDC 31 specifies that the probability of rapidly propagating fracture of the RCPB be minimized. GDC 32 specifies that components which are part of the RCPB have the capability of being periodically inspected to assess their structural and leaktight integrity.

The FENOC response [Cam01a] to the NRC Bulletin 2001-01 applies the GDC against the situation of potentially cracked nozzles at Davis-Besse. Specifically the following points were made:

- The presence of cracked and leaking vessel head penetration (VHP) nozzles is not consistent with GDC14 or GDC 31.
- Inspection practices that do not permit reliable detection of VHP nozzle cracking are not consistent with GDC 32.

The situation regarding primary coolant leakage can be summarized as follows. The Davis-Besse technical specifications (TS) present a definitive criterion that allows no RCPB leakage. The GDC are not as definitive by virtue of their reference to *probability* of occurrence, which is not an absolute or definitive condition. GDC 14 and 31 are in agreement with the TS in principle, but not in their level of definitiveness. Therefore, there exists the possibility that a specific condition can be considered to satisfy the GDC but not the TS. Furthermore, the GDC implemented in the TS for DB allows for 1 gpm of unidentified reactor coolant system (RCS) leakage and 10 gpm of identified RCS leakage, with the interpretation that leakage past seals, flanges, and gaskets is not pressure boundary leakage.

GDC 32 refers to the capability to inspect the leaktight integrity of the nozzles. Inspections were acknowledged to be incomplete because of failure to inspect all nozzles. They were insufficient because it was acknowledged that visual inspection may be inadequate in detecting cracks. By virtue of the inadequacy of the inspections in achieving their intended purpose, GDC 32 was largely not satisfied.

According to the 2002 OIG Event Inquiry [Bel02], FENOC's own risk-informed evaluation estimated that Davis-Besse had between one and nine leaking CRDM nozzles, depending on the analysis used. According to the NRC, FENOC reported [Nrc02c] an estimate of 8.8 leaking nozzles to ACRS. From the results and analysis of the inspection data from five other B&W plants that revealed 16 cracked nozzles in 15 reactor years of operation [Cam01c] there should be 1-2 leaking nozzles since the last outage (RFO 12 in April 2000). So from the available data, it was *highly likely* that there were leaks in the pressure boundary. These data were circumstantial as there was no direct evidence of the leaks, in part due to the inadequacy of the visual inspection techniques.

Given that positive identification of nozzle leakage was not obtainable because of the nature and capability of the inspections, and given that multiple analyses show that as many as 9 leaking nozzles were likely, it can be concluded that Davis-Besse was *likely* in violation of their Technical Specifications. This point was further discussed in the NRC Significance Assessment Report [Dye03].

The incorporation of PRA into the decision-making process at NRC should have compelled the NRC to consider the likelihood of leaking nozzles in the decision on whether to allow Davis-Besse to continue to operate. However, "the NRR Director told OIG that from a legal point of view, there was an issue about constructing an order without knowing with *certainty* that there were cracks" [Bel02]. This position had a significant impact on the NRC decision as the key decision-maker in this case, Brian Sheron, believed that NRC had no case to shut down the plant based on the technical specification that there be no RCPB leakage. The potential conflict between PRA and legal considerations must be resolved for PRA to play any role in the decision-making process of the NRC.

5.3 Balance between Probabilistic and Deterministic Indicators for Risk Assessment

NRC management is responsible for decision-making. The technical staff is responsible for providing the technical case that serves as the foundation for decisions by management. The technical case includes both deterministic and PRA analysis that both involve models, data and calculations.

NRC has adopted "risk-informed" decision-making. However, the process is ill-defined and lacks guidelines as to exactly how it is supposed to work. The management does not have a set formula, process or procedure for incorporating PRA into its decision-making process. Brian Sheron was the key decision-maker in the Davis-Besse case. He stated in the December 11 interview with the review team that the PRA analysis was used as a "calibration point" that gives NRC a ballpark figure of the risk. He indicated that the PRA value is not of much consequence unless it is of a "wildly" extreme value. He also indicated that there is little clear guidance on the use of PRA in the decision-making process. This point was supported by comments from Jack Strosnider and Gary Holahan who confirmed in their December 11 interview with the review team that there is no documentation or guidance that outlines to what extent or how the NRC should weigh the resultant risk number and uncertainty with respect to the ultimate decision.

This viewpoint indicates that NRC has no predetermined methodology to weigh the PRA result against a deterministic result or other factors. That is, the value assigned to the PRA analysis is largely at the discretion of the decision-maker and there is no guidance as to the weight to assign to this result. Such a process can result in a decision in which PRA plays a role anywhere from 0 to 100%. Clearly, there is need for the NRC to provide guidance for the use of PRA in decision-making.

6. Review of the November 2001 NRC Decision Regarding Davis-Besse

6.1 Involvement of NRC Staff and Management in the DB Decision

The basis of the November 28 decision to allow Davis-Besse to operate until February 16 was a meeting involving both technical staff and management. The meeting was called by Brian Sheron and was held on November 28, 2001. Following discussion of the various issues regarding Davis-Besse, Brian Sheron asked the staff if they could accept an extension of operation of the plant until February 16, 2002. Three staff members had objections. Mr. Sheron then reframed the question and asked the staff if any of them thought that Davis-Besse was not safe to operate until that date. None thought that this was the case. Based on this result, NRC accepted the February 16, 2002 date proffered by FENOC.

During the discussion, both deterministic analyses and PRA results were considered. However, a cost-benefit type of analysis of the situation was not performed. In an interview with the review team, Richard Barrett explained that NRC followed the RG 1.174 and RIS 2001-02 [Nrc01b] argument, based on a "special circumstance." This special circumstance was that the regulations (ASME inspection codes) at the time were not adequate to detect cracked and/or leaking nozzles and thus NRC had to take special action to address the special circumstance. Once the existence of a special circumstance was established, NRC used RG 1.174 to determine if the problem was risk significant enough. NRC determined that the problem was not risk significant, per RG 1.174, because "defense-in-depth" was preserved. Therefore, NRC did not consider the third factor, which would have been "higher level NRC management thoughts," such as a "cost-benefit" analysis or impact/burden on license.

However, as noted by several staff, there was pressure on the NRC from industry, Congress and the NRC Commissioners to keep plants running. It is not clear how much influence this pressure had on the decision-making process.

The transparency of the decision-making process within NRC is not uniform. In the case of a shutdown order, the Executive Director for Operations (Office Director) would be the official responsible for signing the order. If the issue does not involve an order, the process is less clear. The specification of decision-maker appears to depend on the importance of the issue. There does not appear to be a policy that identifies what individuals are empowered to make what decisions. Strosnider and Holahan indicated that a routine response to a generic letter may be handled by a project manager, or perhaps by the Divisions of Licensing Project Management, with the concurrence of the involved sections or other divisions. NRC has no standard process or guidelines for decision-making. Sometimes the decision process involves a memo describing the licensee's request and NRC's response that is routed around and signed off on by relevant NRC staff. Other times, NRC will pull together a meeting of decision stakeholders.

The lack of an established and well-defined process for decision-making within the agency is a significant problem that needs to be addressed.

6.2 Coordination among NRR, RES, and Inspectors

The analysis and decision-making process for the Davis-Besse case involved numerous individuals and offices. Included in the consideration of issues regarding Davis-Besse were the Directorate for Project Licensing & Technical Analysis, the Division of Engineering, and Division of System Safety and Analysis and the technical staff of the several Branches that report to those Division Directors of the Office of Nuclear Reactor Regulation (NRR). In addition, the Office of Research (RES) and ACRS played roles, as did the regional office and the regional inspector at Davis-Besse.

While there were a number of individuals and offices involved in the technical assessment of nozzle cracking, the interplay between offices and individuals is impossible to reconstruct. However, there are two cases that highlight problems with communication between offices and between individuals. The first is in the assessment of the initiating event probability. Based on interviews with some 12 different individuals, all significantly involved in the Davis-Besse issue and analysis, and spanning two Offices, one Directorate, two Divisions and several Branches, there was no sense of understanding about how the initiating event probability used in the PRA analysis was determined and by whom. In fact, the origin of the value for the initiating event probability that appears to have been used in the PRA analysis was variously ascribed to Bill Shack at ANL, FENOC, Framatome and EMC[2]. Further, the perception of who within NRC was responsible for establishing this quantity was not consistent. This situation indicates a very uneven understanding of one of the key underlying quantities for the entire PRA analysis. The origin of this term remains an outstanding issue, even with the February 2004 NRC response [Chu04]. It was clear that there was substantial interaction among offices and individuals during the period of intense analysis in the Fall of 2001. However, communication did not appear to be well structured, complete or effective in establishing a value for the initiating event probability.

A second problem was evident in the communication between the various components (headquarters, regional office, regional inspector at Davis-Besse) of the NRC. The resident inspector appears to have played little or no role in providing information relevant to the issues being analyzed at NRC HQ. Further, there appears to have been no communication between the resident inspector and HQ. In the December 11th interview with the review team, Mr. Strosnider stated that it was rare one would think a resident inspector would offer substantive help. He did not believe that the resident inspector at Davis-Besse was, in fact, contacted. He also believed that the resident inspector is busy with other things, and that he probably had not been part of the vessel head inspections, and that he lacked the technical aptitude needed to contribute to the issue.

There were several indications of operational irregularities that should have been noted by an inspector in residence at the plant. These include: 1) radiological surveys showing a contamination plume effect originating from the service structure ventilation exhaust over the East D-ring [Dye02], 2) significant increase in the cleaning of containment air coolers, 3) the removal of fifteen, 5-gallon buckets of boric acid from the ductwork and plenum of the containment air coolers and the discovery of significant boric acid elsewhere in the containment, such as service water piping, stairwells, and other areas of low ventilation, and 4) the sudden change to rust-colored boric acid in June of 1999. That these events were occurring without the knowledge or appreciation of the resident NRC inspector highlights a major weakness of the role of the resident inspector in helping to ensure safe operation of the plant at which he/she is stationed.

6.3 Arbitrariness of the Requested Shutdown Date

The 12/31/01 date for completing inspections of reactor vessel head nozzles imposed on licensees by the NRC was arbitrarily set. The arbitrariness of the 12/31/01 date was confirmed by Brian Sheron in his interview with the review committee in which he stated that there was nothing magical about the December 31st date, and that it just as easily could have been February 28th or March 31st.

The arbitrariness of the date caused difficulty for the NRC when challenged by FENOC. The challenge resulted in a perceived reversal of the burden of proof from the licensee to the NRC. NRC believed that they needed to make a case in order to force a shutdown of DB to look for cracks. Unfortunately, their authority to act was perceived to be undermined by the lack of a defensible rationale for the selection of the inspection date.

NRC has been encouraging the use of risk analysis as part of the risk-informed decision-making process. Yet NRC did not consider including risk analysis in the original call for inspection. The inclusion of risk analysis in the formulation of the inspection date could have provided the NRC with the justification for enforcement that they lacked under the present circumstances. If the call for inspection were based on a risk-informed decision-making strategy, then the calculations of the likelihood of nozzle failure and LOCA would have provided the support they needed to call for an inspection. The practical considerations in this strategy are not trivial. Yet had NRC followed its commitment to incorporate risk analysis in its decision-making process at the outset, the decision regarding Davis-Besse may have been much more straightforward.

6.4 The Role of NRC's Advisory Committee on Reactor Safeguards

Although we recognize that ACRS does not provide routine guidance on plant-specific issues, we feel that NRC staffs should have recognized the CRDM nozzle failures as a generic issue and should have solicited in-depth assistance from ACRS before the 28 November 2001 decision. Thus, relying on a narrow interpretation of the CRDM nozzle failure issues, the staff missed an opportunity to obtain important expert perspectives on the issues. We recommend that the NRC staff make more direct use of ACRS to augment in-house expertise on the staff, which may be limiting at times.

6.5 NRC Staff Workload Affecting Its Ability for Detailed Risk Assessment

An NRC manager raised the question if NRC had sufficient personnel, given the workload, to perform detailed studies on complex regulatory or licensing issues such as the Davis-Besse case. Although the upper level management seems to be satisfied with the overall staff performance, we recommend a review of the workload and technical competence of the staff required to provide licensing and regulatory support in a timely manner.

6.6 Davis-Besse, NRC, and Three Mile Island

The human errors on the parts of Davis-Besse and NRC, resulting in a near miss of a serious accident, echo a similar chain of events that originated at Davis-Besse in 1977 and culminated in America's most serious reactor accident at Three Mile Island in 1979. It began in September 1977 at Davis-Besse when a relief valve on the reactor coolant pressurizer stuck open. The coolant pressure fell but the water level in the pressurizer increased, the result of an anomaly in the pressurizer piping. Thinking that the reactor was getting too much water, the operator improperly interfered with the high-pressure injection system. Fortunately, a supervisor recognized what was happening and closed the relief valve twenty minutes later and re-admitted coolant. No damage was done to the reactor because it had been operating at only 9 percent power.

The incident was investigated by both NRC and by B&W, the reactor supplier, but no information calling attention to the correct operating actions was provided to other utilities. A B&W engineer had stated in an internal memorandum that if the Davis-Besse event had occurred in a reactor operating at full power, "it is quite possible, perhaps probable, that core uncovering and possible fuel damage would have occurred."

In 1978 an NRC official pointed out the likelihood of erroneous operator action in B&W reactors. The NRC did not notify utilities about the lessons learned at Davis-Besse and the pressing need for new training to avoid the confusing interpretation of water level indicators at B&W plants. Fourteen months later the core-melt accident happened at Three Mile Island.

In March 1979, a similar B&W reactor was operating at full power at Three Mile Island in Pennsylvania. Again, the pressure relief valve stuck open, reactor coolant escaped, coolant pressure fell and the operators made the same mistake as had the operators two years earlier at Davis-Besse. They turned off the high-pressure coolant injection. Unfortunately, the ensuing control room confusion did not lead to early diagnosis and restoration of reactor water. With the high-pressure injection water incorrectly turned off, the reactor continued to generate heat and boil coolant, ultimately uncovering the reactor core and melting a substantial portion of the reactor fuel. When a supervisor finally diagnosed the problem and restored high-pressure injection water, some two hours later, enormous fuel damage had been done and considerable radioactivity released to the reactor building.

The President's Commission on the Accident at Three Mile Island [Kem79] concluded that the major factor that turned the TMI incident into a serious accident was inappropriate operator action, deficiencies in training and failure of responsible organizations, especially the NRC, to learn the proper lessons from previous incidents. There was a serious lack of recognition of the safety implications of new information and there was serious lack of questioning of the adequacy of assumptions made in the reactor design, in the operating procedures, and in the follow up of events. The Commission concluded that, starting with the Davis-Besse 1977 event and given all the deficiencies of the safety system and its regulation, an accident like Three Mile Island was eventually inevitable.

For many months and even years it was not realized that the TMI accident had resulted in such extensive core damage. More responsive earlier analyses by NRC of the 1977 Davis-Besse precursor event and its potential consequences would have alerted NRC to forewarn the utilities of the incipient danger. Similarly, the seeming lack of aggressive followup by NRC and industry to understand the risks from the recent near miss at Davis-Besse is a serious concern. History should not be allowed to repeat itself.

7. Recommendations for Improved Use of Probabilistic Risk Assessment

There are several ways in which NRC can improve the use of PRA in its decision-making process:

(1) Establish an appreciation for PRA across the spectrum of NRC technical and managerial personnel. There is great divergence in the appreciation for, and understanding of PRA and its value in the decision-making process. In a sense, NRC needs to get their staff "on the same page" with regard to PRA applications in regulatory and licensing issues.

(2) Establish a set of guidelines for the use of PRA in decision-making. No guidelines currently exist for how PRA should be incorporated into the decision-making process other than the general philosophy that risk analysis should be part of a risk-informed decision-making process. A set of guidelines that establishes the level and nature of consideration of PRA is needed. In particular, guidance should be provided on how to balance PRA results against deterministic or qualitative evaluations, especially when the PRA results are subject to large uncertainties.

(3) Establish a set of guidelines for how decisions are made at NRC and by whom. This is a necessary precursor to the success of recommendation 2. The decision-making process must be defined in order to incorporate risk analysis into that process. Further, the offices and individuals responsible for making decisions need to be defined in order to successfully determine who needs to be aware of and familiar with PRA as discussed in recommendation 1.

(4) Establish a better protocol for estimating and incorporating uncertainties in PRA. PRA results without associated uncertainties are of little value. As a result, it is difficult to incorporate results of an analysis into a decision strategy without an understanding of the bounds of the validity of the result.

(5) Provide for unanticipated events. Corrosion of the Davis-Besse pressure vessel head was not an anticipated event. As put by NRC personnel, it was not even on the radar screen. As such, it was not incorporated into the event tree analysis in PRA. However, PRA needs to be able to anticipate the consequences of such oversight.

(6) Establish a better system at NRC for recognizing generic problems and transmitting information and concerns about these potential problems to other plants.

(7) NRC should issue preliminary analyses of risks from nozzle cracking that include leakage through axial cracks, evaporation of leaking coolant, concentration of and corrosion by boric acid, corrosion of the carbon-steel vessel and the vessel liner, the time-dependent probability of rupture of the corroded vessel, core damage resulting from loss of coolant, and the effects of human failure to make and interpret surveillance inspections. The results and possible interpretations of the recent Oak Ridge tests of vessel failure should be made known to the safety community.

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Davis-Besse Task Force Recommendations to NRC and Their Status, as of March 2004

Recommendation	NRC actions and status as of March 2004
Completed recommendations	
Either fully implement or revise guidance to manage licensee commitments. Determine whether the periodic report on commitment changes submitted by licensees should continue.	Revised instructions for these submittals and reviews to ensure that these tasks are accomplished. Completed in May 2003.
Determine if stress corrosion cracking models are appropriate for predicting susceptibility of vessel head penetration nozzles to pressurized water stress corrosion cracking. Determine if additional analysis and testing is needed to reduce modeling uncertainties for their continued applicability in regulatory decision making.	Evaluated existing stress corrosion cracking models for their continuing use in determining susceptibility. Completed in July 2003.
Revise the problem identification and resolution approach so that safety problems noted in daily licensee reports are reviewed and assessed. Enhance guidance to prescribe the format of information that is screened when deciding which problems to review.	Revised inspection procedure for determining licensee ability to promptly identify and resolve conditions adverse to quality or safety. Completed in September 2003.
Provide enhanced inspection guidance to pursue issues and problems identified during reviews of plant operations.	Revised inspection procedure for determining licensee capability to promptly identify and resolve conditions adverse to quality or safety. Completed in September 2003.
Revise inspection guidance to provide for longer-term follow-up of previously identified issues that have not progressed to an inspection finding.	Revised inspection procedure for determining licensee capability to promptly identify and resolve conditions adverse to quality or safety. Completed in September 2003.
Revise inspection guidance to assess (1) the safety implications of long-standing unresolved licensee equipment problems, (2) the impact of phased in corrective actions, and (3) the implications of deferred plant modifications.	Revised inspection procedure for determining licensee capability to identify and resolve conditions adverse to quality or safety. Completed in September 2003.
Revise inspection guidance to allow for establishing reactor oversight panels even when a significant performance problem, as defined under NRC's Reactor Oversight Process, does not exist.	Revised inspection guidance for establishing reactor oversight panels. Completed in October 2003.
Assess the scope and adequacy of requirements for licensees to review operating experience.	Included in NRC's recommendation to develop a program for collecting, analyzing, and disseminating information on experiences at operating reactors. Completed in November 2003.
Ensure inspector training includes (1) boric acid corrosion effects and control, and (2) pressurized water stress corrosion cracking of nickel-based alloy nozzles.	Developed and implemented Web-based training and a means for ensuring training is completed. Completed in December 2003.
Provide training and reinforce expectations to managers and staff to (1) maintain a questioning attitude during inspection activities, (2) develop inspection insights from Davis-Besse on symptoms of reactor coolant leakage, (3) communicate expectations to follow up recurring and unresolved problems, and (4) maintain an awareness of surroundings while conducting inspections. Establish mechanisms to perpetuate this training.	Developed Web-based inspector training and a means for ensuring that training has been completed. NRC headquarters provided an overview of the training to NRC regional offices. (Training modules will be added and updated as needed.) Completed in December 2003.
Reinforce expectations that regional management should make every effort to visit each reactor at least once every 2 years.	Discussed at regional counterparts meeting. Completed in December 2003.
Develop guidance to address impacts of regional oversight panels on regional resource allocations and organizational alignment.	Evaluated past and present oversight panels. Developed enhanced inspection approaches for oversight panels and issued revised procedures. Completed in December 2003.

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Recommendation	NRC actions and status as of March 2004
Evaluate (1) the capacity to retain operating experience information and perform long-term operating experience reviews; (2) thresholds, criteria, and guidance for initiating generic communications; (3) opportunities for more gains in effectiveness and efficiency by realigning the organization (i.e., feasibility of a centralized operating experience "clearinghouse"); (4) effectiveness of the generic Issues program; and (5) effectiveness of internal dissemination of operating experience information to end users.	Developed program objectives and attributes and obtained management endorsement of a plan to implement the recommendation. Developed specific recommendations to improve program. Evaluation completed in November 2003. (Implementation of recommendations resulting from this evaluation expected to be completed in December 2004.)
Ensure that generic requirements or guidance are not inappropriately affected when making unrelated changes to other programs, processes, guidance, etc.	Revised inspection guidance. Completed in February 2004.
Develop inspection guidance to assess scheduler influences on amount of work performed during refueling outages.	Revised the appropriate inspection procedure. Completed in February 2004.
Establish guidance to ensure that NRC decisions allowing licensees to deviate from guidelines and recommendations issued in generic communications are adequately documented.	Update guidance to address documentation. Develop training and distribute to NRC offices and regions to emphasize compliance with the updated guidance. Follow up to assess the effectiveness of the training. Completed follow-up in February 2004.
Develop or revise inspection guidance to ensure that NRC reviews vessel head penetration nozzles and the reactor vessel head during licensee inspection activities.	Develop or revise inspection guidance to ensure that nozzles and the vessel head are reviewed during licensee inspection. Issued interim guidance in August 2003 and a temporary inspection procedure in September 2003. Additional guidance expected in March 2004.
Develop inspection guidance to assess (1) repetitive or multiple technical specification actions in NRC inspection or licensee reports, and (2) radiation dose implications for conducting repetitive tasks.	Revise the appropriate inspection procedure to reflect this need. Completion expected in March 2004.
Develop guidance to periodically inspect licensees' boric acid corrosion control programs.	Issued temporary guidance in November 2003. Completion of further inspection guidance changes expected in March 2004.
Reinforce expectations for managers responsible for overseeing operations at nuclear power plants regarding site visits, coordination with resident inspectors, and assignment duration. Reinforce expectations to question information about operating conditions and strengthen guidance for reviewing license amendments to emphasize consideration of current system conditions, reliability, and performance data in safety evaluation reports. Strengthen guidance for verifying licensee-provided information.	Update project manager handbook that provides guidance on activities to be conducted during site visits and interactions with NRC regional staff. Also, revise guidance for considering plant conditions during licensing action and amendment reviews. Completion expected in March 2004.
Assemble and analyze foreign and domestic information on Alloy 600 nozzle cracking. If additional regulatory action is warranted, propose a course of action and implement a schedule to address the results.	Assemble and analyze alloy 600 cracking data. Completion expected in March 2004.
Recommendations due to be completed between April and December 2004	
Conduct an effectiveness review of actions taken in response to past NRC lessons-learned reviews.	Review past lessons-learned actions. Completion expected in April 2004.
Provide inspection and oversight refresher training to managers and staff.	Develop a training module. Completion expected in June 2004.

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Recommendation	NRC actions and status as of March 2004
Establish guidance for accepting owners group and industry recommended resolutions for generic communications and generic issues, including guidance for verifying that actions are taken.	Revise office instructions to provide recommended guidance. Completion expected in June 2004.
Review inspection guidance to determine the inspection level that is sufficient during refueling outages, including inspecting reactor areas inaccessible during normal operations and passive components.	Revised an inspection procedure to reflect these changes. Some inspection procedure changes were completed in November 2003, and additional changes are expected in August 2004.
Evaluate, and revise as necessary, guidance for proposing candidate generic issues.	Evaluate and revise guidance. Completion expected in October 2004
Assemble and analyze foreign and domestic information on boric acid corrosion of carbon steel. If additional regulatory action is warranted, propose a course of action and implement a schedule to address the results.	Review Argonne National Laboratory study on boric acid corrosion. Analyze data to revise inspection requirements. Completion expected in October 2004.
Conduct a follow-on verification of licensee actions to implement a sample of significant generic communications with emphasis on those that are programmatic in nature.	Screen candidate generic communications to identify those most appropriate for follow-up using management-approved criteria. Develop and approve verification plan. Completion expected in November 2004.
Strengthen inspection guidance for periodically reviewing licensee operating experience.	Incorporated into the recommendation pertaining to NRC's capacity to retain operating experience information. Completion expected in December 2004.
Enhance the effectiveness of processes for collecting, reviewing, assessing, storing, retrieving, and disseminating foreign operating experience.	Incorporated into the recommendation pertaining to NRC's capacity to retain operating experience information. Completion expected in December 2004.
Update operating experience guidance to reflect the changes implemented in response to recommendations for operating experience.	Incorporated into the recommendation pertaining to NRC's capacity to retain operating experience information. Completion expected in December 2004.
Review a sample of NRC evaluations of licensee actions made in response to owners groups' commitments to identify whether intended actions were effectively implemented.	Conduct the recommended review. Completion expected in December 2004.
Develop general inspection guidance to periodically verify that licensees implement owners groups' commitments.	Develop inspection procedure to provide a mechanism for regions to support project managers' ability to verify that licensees implement commitments. Completion expected in December 2004.
Conduct follow-on verification of licensee actions pertaining to a sample of resolved generic issues.	No specific actions have been identified. Completion expected in December 2004.
Review the range of baseline inspections and plant assessment processes to determine sufficiency to identify and dispose of problems like those at Davis-Besse.	No specific actions have been identified. Completion expected in December 2004.
Identify alternative mechanisms to independently assess licensee plant performance for self-assessing NRC oversight processes and determine the feasibility of such mechanisms.	No specific actions have been identified. Completion expected in December 2004.
Establish measurements for resident inspector staffing levels and requirements, including standards for satisfying minimum staffing levels.	Develop standardized staffing measures and implement details. Metrics were developed in December 2003. Completion expected in December 2004.
Structure and focus inspections to assess licensee employee concerns and a "safety conscious work environment."	No specific actions have been identified. Completion expected in December 2004.

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Recommendation	NRC actions and status as of March 2004
Recommendations due to be completed in calendar year 2005	
Develop inspection guidance and criteria for addressing licensee response to increasing leakage levels and/or adverse trends in unidentified reactor coolant system leakage.	Develop recommendations for guidance with action levels to trigger greater NRC interaction with licensees in response to increased leakage. Completion expected in January 2005.
Reassess the basis for the cancellation, in 2001, of certain inspection procedures (i.e., boric acid control programs and operational experience feedback) to assess if these procedures are still applicable.	Review revised procedures and reactivate as necessary. Completion expected in March 2005.
Assess requirements for licensee procedures to respond to plant alarms for leakage to determine whether requirements are sufficient to identify reactor coolant pressure boundary leakage.	Review and assess adequacy of requirements and develop recommendations to (1) improve procedures to identify leakage from boundary, (2) establish consistent technical specifications for leakage, and (3) use enhanced leakage detection systems. Completion expected in March 2005.
Determine whether licensees should install enhanced systems to detect leakage from the reactor coolant system.	Re-evaluate the basis for current leakage requirements and assess the capabilities of current leakage detection systems. Develop recommendations to (1) improve procedures for identifying leakage, (2) establish consistent technical specifications, and (3) use enhanced leakage detection systems. Completion expected in March 2005
Inspect the adequacy of licensee's programs to control boric acid corrosion, including effectiveness of implementation.	Develop guidance to assess adequacy of corrosion control programs, including implementation and effectiveness, and evaluate the status of this effort after the first year of inspections. Guidance expected to be developed by March 2004. Follow-up scheduled for completion in March 2005.
Continue ongoing efforts to review and improve the usefulness of barrier integrity performance indicators and evaluate the use of primary system leakage that licensees have identified but not yet corrected as a potential indicator.	Develop and implement improved performance indicators based on current requirements and measurements. Explore the use of additional performance indicators to track the number, duration, and rate of system leakage. Determine the feasibility of establishing a risk-informed performance indicator for barrier integrity. Completion expected in December 2005.
Recommendations whose completion dates have yet to be determined	
Encourage the American Society of Mechanical Engineers to revise inspection requirements for nickel-based alloy nozzles. Encourage changes to requirements for nonvisual, nondestructive inspections of vessel head penetration nozzles. Alternatively, revise NRC regulations to address the nature and scope of these inspections.	Monitor and provide input to industry efforts to develop revised inspection requirements. Participate in American Society of Mechanical Engineers' meetings and communicate with appropriate stakeholders. Decide whether to endorse the revised American Society of Mechanical Engineers' code requirements. These actions parallel a larger NRC rulemaking effort. Completion date yet to be determined.
Revise processes to require short- and long-term verification of licensee actions to respond to significant NRC generic communications before closing out issues.	Target date to be set upon completion of review of NRC's generic communications program. Completion date yet to be determined.
Determine whether licensee reactor vessel head inspection summary reports should be submitted to NRC and, if so, revise submission requirements and report disposition guidance, as appropriate.	Will be included as part of revised American Society of Mechanical Engineers' requirements for inspection of reactor vessel heads and vessel head penetration nozzles. Completion date yet to be determined.

(Continued From Previous Page)

Recommendation	NRC actions and status as of March 2004
Evaluate the adequacy of methods for analyzing the risk of passive component degradation and integrate these methods and risks into NRC's decision-making processes.	No specific actions have been identified. Completion date yet to be determined.
Review pressurized water reactor technical specifications to identify plants that have nonstandard reactor coolant pressure boundary leakage requirements and change specifications to make them consistent among all plants.	Assessed plants for nonstandard technical specifications. Completed in July 2003. Change leakage detection specifications in coordination with other changes in leakage detection requirements. Completion date yet to be determined.
Improve requirements for unidentified leakage in reactor coolant system to ensure they are sufficient to (1) discriminate between unidentified leaks from the coolant system and leaks from the reactor coolant pressure boundary and (2) ensure that plants do not operate with pressure boundary leakage.	Issue regulations implementing the improved requirements when these requirements are determined. Completion date yet to be determined.
NRC should review a sample of plant assessments conducted between 1998 and 2000 to determine if any identified plant safety issues have not been adequately assessed.	No specific actions have been identified. Completion expected in March 2004.
Recommendations rejected by NRC management	
Review industry approaches licensees use to consider economic factors for inspection and repair and consider this information in formulating future positions on the performance of non-visual inspections of vessel head penetration nozzles.	Recommendation rejected by NRC management. No completion date.
Revise the criteria for review of industry topical reports to allow for NRC staff review of safety-significant reports that have generic implications but have not been formally submitted for NRC review in accordance with the existing criteria.	Recommendation rejected by NRC management. No completion date.

Source: GAO analysis of NRC data.

Comments from the Nuclear Regulatory Commission

Note: GAO comments supplementing those in the report text appear at the end of this appendix.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

May 5, 2004

Mr. James Wells, Director
Natural Resources and Environment
United States General Accounting Office
441 G Street, NW
Washington, D.C. 20548

Dear Mr. Wells:

On behalf of the U.S. Nuclear Regulatory Commission (NRC), I am responding to your letter of April 2, 2004, requesting the NRC's review of the draft report entitled "Nuclear Regulation: NRC Needs to More Aggressively and Comprehensively Resolve Issues Related to the Davis-Besse Nuclear Power Plant's Shutdown" (GAO-04-415). I appreciate the opportunity to provide comments to the General Accounting Office (GAO) on this report.

I am concerned that the draft report does not appropriately characterize or provide a balanced perspective on the NRC's actions surrounding the discovery of the Davis-Besse reactor vessel head condition or NRC's actions to incorporate the lessons learned from that experience into our processes. The NRC also does not agree with two of the report's recommendations, as discussed in the following paragraphs.

See comment 1.

The first sentence of the draft report states: "...oversight did not generate accurate, complete information on plant conditions." I agree that our oversight program should have identified certain evolving plant conditions for regulatory follow-up. This was also identified in the report of the Davis-Besse Lessons Learned Task Force (LLTF) that the NRC formed to ensure that lessons from the Davis-Besse experience are learned and appropriately captured in the NRC's formal processes. However, the draft report does not acknowledge that the NRC, in carrying out its safety responsibilities, must rely heavily on our licensees to provide us with complete and accurate information. In fact, Title 10 of the Code of Federal Regulations Section 50.9 requires that information provided to the NRC by a licensee be complete and accurate in all material respects. The report should clearly indicate that NRC's licensees are responsible for providing us with accurate and complete information. While the NRC's Davis-Besse LLTF concluded that the NRC, the Davis-Besse licensee (FirstEnergy), and the nuclear industry failed to adequately review, assess, and follow up on relevant operating experience, they also noted that the information that FirstEnergy provided in response to Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles" was inconsistent with information identified by the task force. Further, the LLTF report stated that had this information been known in the fall of 2001, "...the NRC may have identified the VHP [vessel head penetration] nozzle leaks and RPV [reactor pressure vessel] head degradation a few months sooner than the March 2002 discovery by the licensee." As you are aware, there is an ongoing investigation by the Department of Justice regarding the completeness and accuracy of information that FirstEnergy provided to the NRC on the condition of Davis-Besse.

See comment 2.

The NRC is particularly concerned about the draft report's characterization of the NRC's use of risk estimates. The statement in the report that the NRC's "estimate of risk exceeded the risk

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levels generally accepted by the agency" is not factually correct. NRC officials pointed out to GAO and GAO's consultants, both in interviews and in written responses to GAO questions, that our estimate of delta core damage frequency was $5x10^{-6}$ per reactor year, not $5x10^{-5}$ per reactor year as indicated in the report. In fact, the NRC staff safety evaluation (attached to a December 3, 2002, letter to FirstEnergy) stated that the change in core damage frequency due to the potential for control rod drive mechanism nozzle ejection was consistent with the guidelines of Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis." The enclosure to this letter provides detailed comments on issues of correctness and clarity in the report, many of which are related to the NRC's estimate of risk at Davis-Besse.

See comment 3.

We disagree with the finding that the NRC does not have specific guidance for deciding on plant shutdowns and with the report's related recommendation identifying the need for NRC to develop specific guidance and a well-defined process for deciding when to shut down a nuclear power plant. We believe our regulations, guidance, and processes that cover whether and when to shut down a plant are robust and do, in fact, provide sufficient guidance in the vast majority of situations. Plant technical specifications, as well as many other NRC requirements and processes, provide a spectrum of conditions under which plant shutdown would be required. Plants have shut down numerous times in the past in accordance with NRC requirements. From time to time, however, a unique situation may present itself wherein sufficient information may not exist or the information available may not be sufficiently clear to apply existing rules and regulations definitively. In these unique instances, the NRC's most senior managers, after consultation with staff experts and given all of the information available at the time, will decide whether or not to require a plant shutdown. Risk information is used in accordance with Regulatory Guide 1.174. This process considers deterministic factors as well as probabilistic factors (i.e., risk information). We regard the combined use of deterministic and probabilistic factors to be a strength of our decision-making process.

See comment 4.

Another issue identified in the draft report as a systemic weakness is that the NRC has not proposed specific actions to address a licensee's commitment to safety, also known as safety culture. We disagree with the report's recommendation that NRC should develop a methodology to assess licensees' safety culture that includes indicators of and/or information on patterns of licensee behavior, as well as on licensee organizational structures and processes. To date, the Commission has specifically decided not to conduct direct evaluations or inspections of safety culture as a routine part of assessing licensee performance due to the subjective nature of such evaluations. As regulators, we are not charged with managing our licensees' facilities. Direct involvement with safety culture, organizational structure, and processes crosses over to a management function. The NRC does conduct a number of assessments that adequately evaluate how effectively licensees are managing safety. These include an inspection procedure for assessing licensees' employee concerns programs, the NRC allegation program, enforcement of employee protection regulations, and safety-conscious work environment assessments during problem identification and resolution (PI&R) inspections. In addition, the NRC's LLTF made several recommendations (which are being addressed) to enhance the NRC's capability in this area. The NRC does not assess, nor does it plan to assess, licensee management competence, capability, or optimal organizational structure as part of safety culture.

See comment 5.

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While there are a number of factual errors in the draft report, as noted in the enclosure, we agree with many of the findings in the draft report. Most of GAO's findings are similar to the findings of the NRC's Davis-Besse LLTF. The NRC staff has made significant progress in implementing actions recommended by the LLTF and expects to complete implementation of more than 70 percent of them, on a prioritized basis, by the end of calendar year 2004. Reports tracking the status of these actions are provided to the Commission semiannually and will continue until all items are completed, at which time a final summary report will be issued.

I have enclosed the NRC's detailed comments on the draft report. If you have any questions, please contact Stacey L. Rosenberg, of my staff, at (301) 415-3868.

Sincerely,

William D. Travers for
Executive Director
for Operations

Enclosure:
1. NRC Comments on GAO Draft Report on Davis-Besse
2. Memorandum from EDO to OIG dated April 19, 2004

NRC Comments on Draft Report, GAO-04-415

See comment 1.

1. The draft report does not speak to a key issue, the responsibility of licensees to provide complete and accurate information to the NRC. In carrying out its safety responsibilities, NRC must rely heavily on our licensees to provide us with complete and accurate information. Title 10 of the Code of Federal Regulations Section 50.9 requires that information provided to the NRC by a licensee be complete and accurate in all material respects. By not recognizing this explicitly and its role in this matter, the draft report conveys the expectation that the NRC staff should have known about the thick layer of boron on the reactor vessel head. The Davis-Besse Lessons Learned Task Force (LLTF), which NRC formed to ensure that lessons from the Davis-Besse experience are learned and appropriately captured in the NRC's formal processes, noted that the information that FirstEnergy provided in response to Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles" was inconsistent with information identified by the task force. Further, the LLTF report stated that had this information been known in the fall of 2001, the NRC may have identified the vessel head penetration (VHP) nozzle leaks and reactor pressure vessel (RPV) head degradation a few months sooner than the March 2002 discovery by the licensee. See also the related information in response #2.

See comment 2.

2. Page 7, first sentence of the last paragraph states: ***"NRC should have but did not identify or prevent the vessel head corrosion at Davis-Besse because both its inspections at the plant and its assessments of the operator's performance yielded inaccurate and incomplete information on plant safety conditions."***

<u>Response</u>: This statement is misleading. We agree that our oversight program should have identified certain evolving plant conditions for regulatory follow-up. This was also

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identified in the report of the Davis-Besse Lessons LLTF. It is the responsibility of licensees to provide the NRC with complete and accurate information. In fact, Title 10 of the Code of Federal Regulations Section 50.9 requires that information provided to the NRC by a licensee be complete and accurate in all material respects. The report should clearly indicate that NRC's licensees are responsible for providing us with accurate and complete information. While the NRC's Davis-Besse LLTF concluded that the NRC, the Davis-Besse licensee (FirstEnergy), and the nuclear industry failed to adequately review, assess, and follow up on relevant operating experience, the LLTF also noted that the information that FirstEnergy provided in response to Bulletin 2001-01 was inconsistent with information identified by the task force. Further, the LLTF report stated that had this information been known in the fall of 2001, the NRC may have identified the vessel head penetration nozzle leaks and the reactor vessel head degradation a few months sooner than the March 2002 discovery by the licensee. As you are aware, there is an ongoing investigation by the Department of Justice regarding the completeness and accuracy of information that FirstEnergy provided to the NRC on the condition of Davis-Besse.

See comment 3.

3. Page 8, last sentence states: ***"Further, the risk estimate indicated that the likelihood of an accident occurring at Davis-Besse was greater than the level of risk generally accepted as being reasonable by NRC."***

Response: This is incorrect. NRC staff explained to the GAO consultants that NRC guidance produces an estimate for the change in core damage frequency of $5x10^{-6}$ per year, not $5x10^{-5}$ as indicated in the GAO report. According to Regulatory Guide (RG) 1.174, for Davis-Besse, this estimate is within acceptable bounds. NRC specifically documented the acceptability of the estimate in the December 2002 assessment. Thus, the December 3, 2002, safety evaluation concluded that the delta core damage frequency was consistent with the guidelines of RG 1.174.

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See comment 6.

4. Page 15 states that borax (i.e., sodium borate) is dissolved in the water. This is incorrect. Please replace the word "borax" with "boric acid crystals."

See comment 7.

5. Page 18, first full paragraph states: ***"NRC, in deciding on when FirstEnergy had to shutdown Davis-Besse for the inspection,..."***
Response: In addition, the staff relied upon information provided by the licensee regarding the condition of the vessel head (i.e., previous leakage and action taken to repair leaks and clean the vessel head).

See comment 8.

6. Page 26, beginning on line 4, states: ***"According to the NRC regional branch chief—who supervised the staff responsible for overseeing FirstEnergy's vessel head inspection activities during the 2000 refueling outage—he was unaware of the boric acid leakage issues at Davis-Besse, including its effects on the containment air coolers and the radiation monitor filters."***
Response: According to the individual to whom this statement is attributed, the statement would be correct if the phrase, "he was unaware...filters" is changed to "he was unaware that boric acid was found on the reactor vessel head during the outage."

See comment 9.

7. Page 27, first sentence states: ***"Similarly, NRC officials said that NRC headquarters had no systematic process for communicating information in a timely manner to its regions or on-site inspectors."***
Response: If the "information" in question refers to issues of potential safety significance into which inspectors should look, then this statement is inaccurate. The systematic process for temporarily focusing inspection activity in a coordinated program-wide manner on high-priority issues is the "Temporary Instruction" (TI) process, which is well established within the NRC Inspection Manual and frequently used. The legitimate point

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to be made is that until the Davis-Besse event, the NRC had not concluded that boric acid corrosion was a sufficient safety concern that reached the threshold for using the TI process.

See comment 10.

8. Page 33, middle paragraph states: ***"For example, concern over alloy 600 cracking led France, as a preventive measure, to develop plans for replacing all of its reactor vessel heads and installing removable insulation to better inspect for cracking."***
Response: French regulators instituted requirements for an extensive, non-visual nondestructive examination inspection program for vessel head penetration nozzles that resulted in plant operators deciding, on the basis of economic considerations, to replace vessel heads in lieu of conducting such examinations.

See comment 11.

9. Page 34, last paragraph states: ***"If such small leakage can result in such extensive corrosion..."***
Response: Small leakage alone was not the cause of the corrosion. It was a combination of prolonged leakage in conjunction with allowing caked-on boron to remain on the vessel head.

See comment 12.

10. Page 36, middle paragraph states: ***"However, NRC decided that it could not order Davis-Besse to shut down on the basis of other plants' cracked nozzles and identified leakage or the manager's acknowledgment of a probable leak. Instead, it believed it needed more direct, or absolute, proof of a leak to order a shutdown."***
Response: As discussed at the NRC-GAO exit conference, plant Technical Specifications, as well as many other NRC requirements and processes, provide a number of circumstances in which a plant shutdown would or could be required, including the existence of reactor coolant pressure boundary leakage while operating at power.

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Please note that there was no legal objections to the draft order and the stated basis for deciding to not issue the order was not an insufficient legal basis.

11. Page 36, last paragraph states: ***"...NRC does not have specific guidance for shutting down a plant when the plant may pose a risk to public health and safety even though it may be complying with NRC requirements."***

See comment 4.

Response: We disagree with this finding and with the report's related recommendation on Page 63 identifying the need for NRC to develop specific guidance and a well-defined process for deciding when to shut down a nuclear power plant. We believe our regulations, guidance, and processes that cover whether and when to shut down a plant are robust and do, in fact, provide sufficient guidance in the vast majority of situations. Plant technical specifications, as well as many other NRC requirements and processes, provide a spectrum of conditions under which plant shutdown would be required. Plants have shut down numerous times in the past in accordance with NRC requirements. From time to time, however, a unique situation may present itself wherein sufficient information may not exist or the information available may not be sufficiently clear to apply existing rules and regulations definitively. In these unique instances, the NRC's most senior managers, after consultation with staff experts and given all of the information available at the time, will decide whether or not to require a plant shutdown. Risk information is used in accordance with RG 1.174. This process considers deterministic factors as well as probabilistic factors (i.e., risk information). We regard the combined use of deterministic and probabilistic factors to be a strength of our decisionmaking process.

See comment 13.

12. Page 38, third paragraph states: ***"At some point during this time, NRC staff also concluded that the first safety principle was probably not being met, although the basis for this conclusion is not known."***

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Response: The report should clarify GAO's basis for this statement. NRC staff believed that the regulations were met.

See comment 14.

13. Page 40, last paragraph states: ***"However, NRC did not provide the assessment until a full year later—in December 2002. In addition, the December 2002 assessment, which includes a 4-page evaluation, does not fully explain how the safety principles were used or met—other than by stating that if the likelihood of nozzle failure were judged to be small, then adequate protection would be ensured."***

Response: The attachment to the December 3, 2002, letter is an 8-page evaluation, not 4 pages. We note this to make sure GAO is referring to the same document. The assessment addresses four of the five safety principles. In the NRC's December 2002 safety evaluation, the staff stated that the criterion related to compliance with the regulations was being met because the inspections performed by the licensee were in conformance with the ASME Code. In addition, the safety evaluation stated that Davis-Besse met the criterion related to defense-in-depth because all three barriers against release of radiation were intact and reliable; they met the margin criterion because even the largest circumferential cracks found in pressurized-water reactors had considerable margin to structural failure, and they met the low-risk impact criterion based on a comparison of delta core damage frequency estimates with the guidelines of RG 1.174. The fifth safety principle, requiring a monitoring program, was not relevant to a decision that lasted only 6 weeks.

See comment 15.

14. Page 42, first paragraph states: ***"Multiplying these two numbers, NRC estimated that the potential for a nozzle to crack and cause a loss-of-coolant accident would increase the frequency of core damage at Davis-Besse by about 5.4x10⁻⁵ per year, or about 1 in 18,500 per year. Converting this frequency to a probability, NRC***

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calculated that the increase in probability of core damage was approximately 5.0×10^{-6}, or 1 chance in 200,000. While NRC officials currently disagree that this was the number it used, this is the number that it included in its December 2002 assessment provided to FirstEnergy. Further, we found no evidence in the agency's records to support NRC's current assertion."

Response: These statements mischaracterize the facts. NRC estimated that the probability of nozzle cracking leading to a loss-of-coolant accident during the first 6 weeks in 2002 would increase the annual core damage frequency (CDF) by about 5.4×10^{-6} per year, or about 1 in 185,000 per year. The estimate of 5×10^{-5} was an intermediate step in our calculation. The estimate of 5×10^{-5} represents the change in CDF if Davis-Besse were allowed to operate for one year without shutting down for inspection of the vessel head. Allowing Davis-Besse to continue to operate for one year was never a consideration. Thus, multiplying by the fraction of time in one year under consideration (in this case 7 weeks) was the final step in the calculation of delta CDF. The confusion about the estimate NRC used in the decisionmaking process may be due to NRC's method of calculating delta CDF for plant conditions which do not persist for the entire year. If this final step (the fraction of the year the plant is allowed to operate) were not part of the calculation, then the risk estimate of allowing the licensee to continue to operate for 7 weeks, as compared to one year, would be the same. Logically, this does not make sense. Therefore, the estimate of 5×10^{-5} does not automatically convert to a probability, as GAO's statement implies. Because the period of operation under consideration was approximately 0.13 years, the annual average change in CDF was about 5×10^{-6} per year, and the increase in the probability of core damage was about 5×10^{-6} as well. NRC officials **agree** that 5×10^{-6} was the estimate used in the decisionmaking process and is the estimate provided in the December 2002 assessment.

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See comment 16.

See comment 17.

See comment 18.

15. Page 42, second paragraph states: ***"For example, the consultants concluded that NRC's estimate of risk was incorrectly too small, primarily because the calculation did not consider corrosion of the vessel head."***

<u>Response</u>: An underlying assumption in any risk assessment is that you have complete and accurate information from the licensee. NRC staff was of the understanding that efforts had been made to remove boric acid accumulation from the vessel head during previous outages. For all six B&W plants that found signs of penetration leakage, the leakage manifested itself in the form of small amounts of dry boron crystals on the vessel head, which are not corrosive, and did not produce any corrosion on the vessel heads of these six B&W plants. Boron leaking onto a clean vessel head does not cause corrosion. Therefore, corrosion this extensive was not anticipated at the time. Also, it is important to note that had Davis-Besse shut down on December 31, 2001, the same corrosion would have been found.

16. Page 43, first full paragraph discusses the experience at French nuclear power plants.

<u>Response</u>: The NRC staff was aware of the issue as illustrated in an internal memorandum dated December 15, 1994, from Brian Grimes to Charles Rossi.

17. Page 44, first full paragraph states: ***"Third, NRC's analysis was inadequate because the risk estimates were higher than generally considered acceptable under NRC guidance. Despite PRA's [probabilistic risk assessment's] important role in the decision, our consultants found that NRC did not follow its guidance for ensuring that the estimated risk was within levels acceptable to the agency.*** Page 45, first paragraph states: ***"...NRC's PRA estimate for Davis-Besse resulted in an increase in the frequency of core damage of $5.4x10^{5}$ or 1 chance in about 18,500 per year was higher than the acceptable level."***

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Response: This conclusion is not supported by the facts and it is misleading. The estimate referenced by GAO is an intermediate calculation in our process, and was not used, and should not be used, in the decisionmaking process. NRC staff explained to the GAO consultants that NRC guidance produces an estimate for the change in core damage frequency of $5x10^{-6}$ per year, not $5x10^{-5}$ as indicated in the GAO report. According to RG 1.174, for Davis-Besse, this estimate is within acceptable bounds. NRC specifically documented the acceptability of the estimate in the December 2002 assessment. Thus, the December 3, 2002, safety evaluation concluded that the delta CDF was consistent with the guidelines of RG 1.174.

18. Page 45, first paragraph states: ***"NRC's guidance for evaluating requests to relax NRC technical specifications suggests that a probability increase higher than $5x10^{-7}$ or 1 chance in 2 million is considered unacceptable for relaxing the specifications. Thus, NRC's estimate would not be considered acceptable under this guidance."***

See comment 19.

Response: This criterion in RG 1.177 is not relevant to the Davis-Besse decision. It is confined to decisions on allowed outage times (AOT) for equipment, and is defined to avoid very high instantaneous risks (CDF > 10^{-3}) for very short periods (5 hours).

19. Page 46, first full paragraph states: ***"Lastly, NRC's analysis was inadequate because the agency does not have clear guidance for how PRA estimates are to be used in the decision-making process."***

See comment 20.

Response: The NRC's process for risk-informed decision-making is considerably more robust than characterized in this section. Regulatory Guide 1.174 comprises 40 pages of guidance on how to use risk in decisions of this type, and it is backed up by equally detailed guidance for specific types of decisions such as technical specifications, in-service inspection programs, in-service testing, and quality assurance. The NRC has

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amassed a great deal of experience in application of the guidance. Risk assessment is a tool to help better inform decisions that are based on engineering judgements.

20. Page 46, last paragraph states: ***"It is not clear how NRC staff used the PRA risk estimate in the Davis-Besse decision-making process."***

See comment 21.

Response: The December 3, 2002, safety evaluation clearly states how the PRA estimate was used in the decisionmaking process; the estimate was compared with the guidelines of RG 1.174. The safety evaluation also points out that NRC staff who are expert in non-PRA disciplines such as probabilistic fracture mechanics, gave more weight to deterministic factors, such as the structural margin that remains in the nozzles with circumferential cracks. The NRC considers the combined use of deterministic and probabilistic factors to be a strength of our decisionmaking process.

21. Page 48, last paragraph states: ***"...NRC had made progress in implementing the recommendations, although some completion dates have slipped."***

See comment 22.

Response: The schedules for implementation of all high priority recommendations have not slipped. The implementation schedule for certain low or medium priority recommendations slip only in accordance with NRC's Planning, Budgeting and Performance Management (PBPM) process, which explicitly considers safety significance when making budget priority decisions.

22. Page 51, top of page, first full bullet states: ***"One recommendation is directed at improving NRC's generic communications program. NRC is..."***

See comment 23.

Response: We recommend re-wording this as follows: "One recommendation is directed at improving follow up of licensee actions taken in response to NRC generic communications. A Temporary Instruction (Inspection Procedure) is currently being

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developed to assess the effectiveness of licensee actions taken in response to generic communications. Additionally, improvements in the verification of effectiveness of generic communications are planned as a long-term change in the operating experience program."

See comment 24.

23. Page 51, last paragraph states: ***"...NRC's revised inspection guidance for more thorough examinations of reactor vessel heads and nozzles, as well as new requirements for NRC oversight of licensees' corrective action programs, will require at least an additional 200 hours of inspection per reactor per year."***
Response: It is unclear where this number comes from, but the changes to the corrective action program procedure require only about 16 hours per reactor year for the trend review.

See comment 25.

24. Page 53, first paragraph discusses the NRC's Office of the Inspector General's (OIG's) findings on communications.
Response: The NRC's actions are not limited primarily to improving communication about boric acid corrosion and cracking. There are multiple task force recommendations, and other NRC initiatives, that are aimed at addressing the broader implications stemming from communication lapses noted by the task force and the OIG. For example, actions have been implemented to more effectively disseminate operating experience to end users, reenforce a questioning attitude in the inspection staff, and discuss Davis-Besse lessons learned at various forums.

NRC's initial response to the OIG did not directly address the broader actions we are taking to improve communications. Our response to the OIG only indirectly addressed this by discussing the operating experience program enhancements. Part of the

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enhancements to the operating experience program is the expectations for improved communications. In addition, communication improvement initiatives with internal and external stakeholders are in progress to address shortcomings in this critical area. Our revised response to the OIG on this issue, dated April 19, 2004, is provided as Enclosure 2.

25. Page 53, second paragraph states: ***"NRC's Davis-Besse task force did not make any recommendations to address two systemic problems: evaluating licensees' commitment to safety and improving the agency's process for deciding on a shutdown."***

See comment 26.

Response: The LLTF did not make a recommendation for improving the agency's process for deciding on a shutdown. This area was not reviewed in detail by the task force because of coordination with the OIG. Moreover, the task force review efforts were focused on why the degradation cavity was not prevented. While related, the shutdown issue had little to do with the degradation cavity.

See comment 5.

The task force made multiple recommendations aimed at enhancing NRC's capability to evaluate the licensees' commitment to safety, by indirect means. Refer to task force recommendations: 3.2.5(1), 3.2.5(2), 3.3.2(2), 3.3.4(5), and Appendix F.

26. Page 54, last paragraph states: ***"This problem identification and resolution inspection procedure is intended to assess the end-results of management's safety commitment rather than the commitment itself."***

See comment 5.

Response: This statement is inaccurate. Regarding its accuracy, the PI&R inspection procedure (IP 71152) actually has six stated inspection objectives (refer to section 71152-01) including: (1) provide for early warning of potential performance issues that could

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result in crossing threshold in the action matrix and (2) to provide insights into whether licensees have established a safety-conscious work environment. Using this IP, inspectors seek factual evidence of the licensee's assumed commitment to safety (by reviewing their identification and correction of actual problems). Inspection issues routinely are raised with regard to a licensee's weakness in correcting recurrent problems or in adequately addressing issues that could become a future significant safety concern. The statement on Page 55 of the report, ***"Furthermore, because NRC directs its inspections at problems that it recognizes as being more important to safety, NRC may overlook other problems until they develop into significant and immediate safety problems"*** does not accurately reflect the stated objectives and demonstrable implementation of IP 71152.

27. Pages 55-56, discuss safety culture.

See comment 5.

Response: To a significant degree, the areas referenced in this draft report are addressed either by NRC requirements or inspection activities. For example, the NRC has requirements limiting work hours for critical plant staff members such as security officers and plant operators. The NRC has requirements governing operator training. Inspectors routinely monitor various licensee meetings and job briefings to evaluate the licensee's emphasis on safety.

Moreover, the NRC has a number of other means to indirectly assess safety culture. Other NRC tools that provide indirect insights into licensee safety culture include:

- inspection procedure for assessing the licensee's employee concerns program,
- NRC's allegation program,
- enforcement of employee protection regulations,

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- Safety-Conscious Work Environment (SCWE) assessments during problem identification and resolution inspections,
- lessons-learned reviews such as the one conducted for the Davis-Besse reactor pressure vessel head degradation; and
- Reactor Oversight Process cross-cutting issues of human performance, problem identification and resolution, and SCWE.

See comment 27.

28. Page 58, paragraph under the first header states: ***"It recognized that NRC's written rationale for accepting FirstEnergy's justification for continued plant operation was not prepared until 1 year after its decision..."***

    Response: For clarification, the documentation of the decision about one year later was corrective action from a task force finding.

See comment 28.

29. Page 58, paragraph under second header states: ***"The NRC task force did not address NRC's failure to learn from previous incidents at power plants and prevent their recurrence."***

    Response: This sentence is factually inaccurate. The task force performed a limited review of past lessons-learned reports and actually identified many more potentially recurring programmatic issues as a result of that review than the three examples cited by the GAO in this section of the draft report. As discussed during the NRC-GAO exit conference, the task force made a recommendation to perform a more detailed effectiveness review of the actions stemming from other past NRC lessons learned reviews (Appendix F). This review is currently in progress.

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

April 19, 2004

MEMORANDUM TO: Hubert T. Bell
Inspector General

FROM: William D. Travers ***/RA Carl J. Paperiello Acting For/***
Executive Director for Operations

SUBJECT: FEBRUARY 2, 2004, OFFICE OF INSPECTOR GENERAL (OIG) MEMORANDUM CONCERNING AGENCY RESPONSE TO OIG EVENT INQUIRY CASE NO. 03-02S (NRC'S OVERSIGHT OF DAVIS-BESSE BORIC ACID LEAKAGE AND CORROSION DURING THE APRIL 2000 REFUELING OUTAGE)

This memorandum responds to your memorandum to Chairman Diaz, dated February 2, 2004, concerning the Nuclear Regulatory Commission (NRC) staff's response of January 12, 2004, to OIG Event Inquiry 03-02S. The referenced OIG event inquiry was initiated in response to a Congressional request that OIG determine how the NRC staff handled Davis-Besse Condition Report (CR) 2000-0782 at the time of discovery in refueling outage (RFO) 12 (2000) and whether the CR was considered in the November 2001 decision to allow Davis-Besse to continue to operate to February 16, 2002. The NRC staff's previous response to OIG (January 12, 2004) regarding this issue provided a matrix of those recommendations from the Davis-Besse Lessons Learned Task Force (DBLLTF) report that specifically addressed the event inquiry findings and referenced the report for a complete picture of the staff's efforts. The OIG response of February 2, 2004, stated that the NRC staff had not addressed the problem of communications as an underlying cause of the findings of the OIG event inquiry and that the agency should include an expectation of improved communication between and among NRC Headquarters and regional staff and should outline specific guidance to achieve this goal. In addition, OIG specifically concluded that "had the [Davis-Besse Nuclear Power Station] DBNPS inspectors been better informed of ongoing NRC industry-wide efforts to address coolant pressure boundary leakage and the effects of boric acid corrosion, they would have recognized the significance of Condition Report 2000-0782 and highlighted the information to regional management."

The DBLLTF report discusses the NRC's and industry's failure to understand the significance of boric acid corrosion of the reactor vessel head. The NRC staff believes that this failure caused the underlying communications lapses. Although the potential for this type of degradation existed previously, the significance of boric acid deposits was not understood by the staff. The assumption throughout NRC was that the boric acid deposits would be in a dry, powder-like form that could easily be removed and would not accumulate in a condition that would be corrosive to the reactor vessel head. As identified in the event inquiry, the inspectors did communicate a substantial amount of information to the region and the NRR Project Manager, particularly regarding the fouling of the containment air coolers and radiation monitor filter

Contact: Edwin M. Hackett, NRR/DLPM/PDII
415-1485

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elements; however, the significance of this information was also not appreciated at the time. This same failure to understand the significance of the situation was the cause of the lack of communication from Headquarters to the regions. Several elements of the matrixed DBLLTF Action Plans address this underlying issue of lack of recognition of the significance of the evidence. The desired outcome for these actions is for all NRC staff to maintain a questioning attitude and lower thresholds for communications concerning materials degradation corrosion.

More broadly, the NRC staff agrees that communications are of critical importance in all aspects of NRC activities and particularly important as an underlying cause for issues discovered at DBNPS. The corrective actions outlined in the DBLLTF Action Plans address communications beyond the topic of boric acid corrosion control. For example, corrective actions in the area of operating experience development and use are focused on enhancing communications. The recommendations to strengthen inspection guidance, institute training to reinforce a questioning attitude on the part of management and staff, and change the Inspection Manual to provide guidance for the staff to pursue issues identified during plant status reviews are intended to establish more definitive expectations for improved communications of operating experience. As discussed in the February 23, 2004, semiannual update report and at the February 26, 2004, Commission meeting, implementation plans for this area are still under development and may significantly influence the way the agency does business in the future. Developing the most effective and efficient communications channels will be key to the successful implementation of an effective operating experience program.

Beyond the DBLLTF Action Plan, the agency has several ongoing initiatives that provide examples of efforts to more broadly improve intra-agency communications. These examples include establishment of a Communication Council reporting to the Executive Director for Operations and the creation of a communications specialist position reporting to the Office of Nuclear Reactor Regulation (NRR) Associate Director for Inspections and Programs. NRR also continues to improve and enhance its Web site as a focused means of communicating with both internal and external stakeholders. From a regional perspective, examples of communication enhancements include lowering the threshold for communication of plant issues on morning status calls, devoting additional time to discussing lessons learned from plant events and inspection findings during counterpart meetings, and developing enhanced guidance for documenting significant operational event followup decisions. Collectively, these examples provide a strong indication that NRC Headquarters and regional staff have begun to internalize two of the most important lessons from the Davis-Besse event. These are that on occasion, information initially considered to have low significance by the first NRC recipient is later found to be of greater significance once the information is shared and evaluated more collegially; and with regard to the complex nature of commercial nuclear power operations, no one person can be aware of all aspects of an issue. As a result, the more information that is shared, the more likely significant problems will be identified and appropriate action(s) taken.

In summary, the NRC staff recognizes that communication failures were an underlying cause of the agency's problems concerning the delayed discovery of the boric acid corrosion at DBNPS. Our January 12, 2004, response to the event inquiry specifically addressed what we considered to be the root cause of the event-specific communication failures, namely that the entire staff did not recognize the potential significance of boric acid corrosion. Expectations for improved communications will be developed as an integral part of our operating experience program enhancements. More broadly, communication improvement initiatives with internal and external

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stakeholders are in progress to enhance agency performance in this critical area of our responsibilities. We regret that our initial response did not clearly address the broader actions we are taking to improve communications and appreciate the opportunity to clarify our response.

cc: Chairman Diaz
Commissioner McGaffigan
Commissioner Merrifield
SECY
LReyes

The following are GAO's comments on the Nuclear Regulatory Commission's letter dated May 5, 2004.

GAO Comments

1. We agree with NRC that 10 C.F.R. § 50.9 requires that information provided to NRC by a licensee be complete and accurate in all material respects, and we have added this information to the report. NRC also states that in carrying out its oversight responsibilities, NRC must "rely heavily" on licensees providing accurate information. However, we believe that NRC's oversight program should not place undue reliance on applicants providing complete and accurate information. NRC also recognizes that it cannot rely solely on information from licensees, as evidenced by its inspection program and process for determining the significance of licensee violations. Under this process, NRC considers whether there are any willful aspects associated with the violation—including the deliberate intent to violate a license requirement or regulation or falsify information. We believe that management controls, including inspection and enforcement, should be implemented by NRC so as to verify whether licensee-submitted information considered to be important for ensuring safety is complete and accurate as required by the regulation. In this regard, as stated in NRC's enforcement policy guidance, NRC is authorized to conduct inspections and investigations (Atomic Energy Act § 161); revoke licenses for, among other things, a licensee's making material false statements or failing to build or operate a facility in accordance with the terms of the license (Atomic Energy Act § 186); and impose civil penalties for a licensee's knowing failure to provide certain safety information to NRC (Energy Reorganization Act § 206).

   With regard to the draft report conveying the expectation that NRC should have known about the thick layer of boron on the reactor vessel head, we note in the draft report that since at least 1998, NRC was aware that (1) FirstEnergy's boric acid corrosion control program was inadequate, (2) radiation monitors within the containment area were continuously being clogged by boric acid deposits, (3) the containment air cooling system had to be cleaned repeatedly because of boric acid buildup, (4) corrosion was occurring within containment as evidenced by rust particles being found, and (5) the unidentified leakage rate had increased above the level that historically had been found at the plant. NRC was also aware of the repeated but ineffective attempts by FirstEnergy to correct many of these recurring problems—evidence that the licensee's programs to identify and correct problems were not effective. Given these indications at Davis-Besse, NRC could have taken more aggressive follow-up action to determine the underlying causes. For example, NRC could have taken action during the fuel outage in 1998, the shutdown to repair valves in mid-1999, or the fuel outage in 2000 to ensure that staff with sufficient knowledge appropriately investigated the types of conditions that could cause these indications, or followed up to ensure that FirstEnergy had fully investigated and successfully resolved the cause of the indications.

2. With respect to the responsibility of the licensee to provide complete and accurate information, see comment 1. As to the Davis-Besse lessons-learned task force finding, we agree that some information provided by FirstEnergy in response to Bulletin 2001-01 may have been inconsistent with some information subsequently identified by NRC's lessons-learned task force, and that had some of this information been known in the fall of 2001, the vessel head leakage and degradation may have been identified sooner than March 2002. This information included (1) the boric acid accumulations found on the vessel head by FirstEnergy in 1998 and 2000, (2) FirstEnergy's limited ability to visually inspect the vessel head, (3) FirstEnergy's boric acid corrosion control procedures relative to the vessel head, (4) FirstEnergy's program to address the corrosive effects of small amounts of reactor coolant leakage, (5) previous nozzle inspection results, (6) the bases for FirstEnergy's conclusion that another source of leakage—control rod drive mechanism flanges—was the source of boric acid deposits on the vessel head that obscured multiple nozzles, and (7) photographs of vessel head penetration nozzles. However, various NRC officials knew some of this information, other information should have been known by NRC, and the remaining information could have been obtained had NRC requested it from FirstEnergy. For example, according to the senior resident inspector, he reviewed every Davis-Besse condition report on a daily basis to determine whether the licensee properly categorized the safety significance of the conditions. Vessel head conditions found by FirstEnergy in 1998 and 2000 were noted in such condition reports or in potential-condition-adverse-to-quality reports. According to a FirstEnergy official, photographs of the pressure vessel head nozzles were specifically provided to NRC's resident inspector, who, although he did not specifically recall seeing the photographs, stated that he had no reason to doubt the FirstEnergy official's statement. NRC had been aware, in 1999, of limitations in FirstEnergy's boric acid corrosion control program and, while it cited FirstEnergy for its failure to adequately implement the program, NRC officials did not

follow up to determine if the program had improved. Lastly, while NRC questioned the information provided by FirstEnergy in its submissions to NRC in response to Bulletin 2001-01 (regarding vessel head penetration nozzle inspections), NRC staff did not independently review and assess information pertaining to the results of past reactor pressure vessel head inspections and vessel head penetration nozzle inspections. Similarly, NRC did not independently assess the information concerning the extent and nature of the boric acid accumulations found on the vessel head by the licensee during past inspections.

On page 2 of the report, we note that the Department of Justice has an ongoing investigation concerning the completeness and accuracy of information that FirstEnergy provided to NRC on the conditions at Davis-Besse. The investigation may or may not find that FirstEnergy provided inaccurate or incomplete information. While NRC notes that it might have detected something months earlier if information had been known in the fall of 2001, we would also note that the degradation of the reactor vessel head likely took years to occur.

3. We believe that the statement is correct. NRC produced an estimate of $5x10^{-5}$ per year for the change in core damage frequency, as we state in the report. NRC specifically documented this calculation in its December 2002 assessment:

   "The NRC staff estimated that, giving credit only to the [FirstEnergy] inspection performed in 1996, the probability of a [control rod drive mechanism] nozzle ejection during the period of operation from December 31, 2001, to February 16, 2002, was in the range of 2E-3 and was an increase in the overall [loss of coolant accident] probability for the plant. The increase in core damage probability and large early release probability were estimated as approximately 5E-6 and 5E-08, respectively."[1]

   The probability of a large early release—5E-6—equates to a frequency of $5x10^{-5}$ per year.[2] As we note in the report, according to NRC's

[1]The numbers 2E-3, 5E-6, and 5E-8 can also be written as $2x10^{-3}$, $5x10^{-6}$, and $5x10^{-8}$.

[2]The probability of an event occurring is the product of the frequency of an event and a given time period. In this case, the time period—7 weeks—was approximated as one-tenth of the year. Thus, $5.4x10^{-5}$ per year multiplied by 0.10 equates to a probability of $5.4x10^{-6}$. According to NRC, it revised $5.4x10^{-6}$ to $5.0x10^{-6}$ to account for uncertainties.

regulatory guide 1.174, this frequency would be in the highest risk zone and NRC would generally not approve the requested change.

On several occasions, we met with the NRC staff that developed the risk estimate in an attempt to understand how it was calculated. We obtained from NRC staff the risk estimate information provided to senior management in late November 2001, as well as several explanations of how the staff developed its calculations. We were provided with no evidence that NRC estimated the frequency of core damage as being $5x10^{-6}$ per year until February 2004, after our consultants and we had challenged NRC's estimate as being in the highest risk zone under NRC's regulatory guide 1.174. Furthermore, several NRC staff involved in deciding whether to issue the order to shut down Davis-Besse, or to allow it to continue operating until February 16, 2002, stated that the risk estimate they used was relatively high.

4. We agree that existing regulations provide a spectrum of conditions under which a plant shutdown could occur and that could be interpreted as covering the vast majority of situations. However, we continue to believe that NRC lacks sufficient guidance for making plant shutdown decisions. We disagree on two grounds: First, the decision-making guidance used by NRC to shut down Davis-Besse was guidance for approving license change requests. This guidance provides general direction on how to make risk-informed decisions when licensees request license changes. It does not address important aspects of decision-making involved in deciding whether to shut down a plant. It also does not provide direction on how NRC should weigh deterministic factors in relation to probabilistic factors in making shutdown decisions. Secondly, while NRC views the flexibility afforded by its existing array of guidance as a strength, we are concerned that, even on the basis of the same information or circumstances, staff can arrive at very different decisions. Without more specific guidance, NRC will continue to lack accountability and the degree of credibility needed to convince the industry and the public that its shutdown decisions are sufficiently sound and reasoned for protecting public health and safety.

5. We are aware that the commissioners have specifically decided not to conduct direct evaluations or inspections of safety culture. We agree that as regulators, NRC is not charged with managing licensees' facilities, but disagree that any direct NRC involvement with safety culture crosses over to a management function. Management is an

embodiment of corporate beliefs and perceptions that affect management strategies, goals, and philosophies. These, in turn, impact licensee programs and processes and employee behaviors that have safety outcomes. We believe that NRC should not assess corporate beliefs and perceptions or management strategies, goals, or philosophies. Rather, we believe that NRC has a responsibility to assess licensee programs and processes, as well as employee behaviors. We cite several areas of safety culture in the report as being examples of various aspects of safety culture that NRC can assess which do not constitute "management functions." The International Atomic Energy Agency has extensive guidance on assessing additional aspects of licensee performance and indicators of safety culture.[3] Such assessments can provide early indications of declining safety culture prior to when negative safety outcomes occur, such as at Davis-Besse.

We also agree that NRC has indirect means by which it attempts to assess safety culture. For example, NRC's problem identification and resolution inspection procedure's stated objective is to provide an early warning of potential performance issues and insight into whether licensees have established safety conscious work environments. However, we do not believe that the implementation of the inspection procedure has been demonstrated to be effective in meeting its stated objectives. The inspection procedure directs inspectors to screen and analyze trends in all reported power plant issues. In doing so, the procedure directs that inspectors annually review 3 to 6 issues out of potentially thousands of issues that can arise and that are related to various structures, systems, and components necessary for the safe operation of the plant. This requires that inspectors judgmentally sample 3 to 6 issues on which they will focus their inspection resources. While we do not necessarily question inspector judgment when sampling for these 3 to 6 issues, NRC inspectors stated that due to the large number of issues that they can sample from, they try to focus on those issues that they believe have the most relevance for safety. Thus, if an issue is not yet perceived as being important to safety, it is less likely to be selected for follow up. Further, even if an issue were selected for follow up and this indicated that the licensee did not properly identify and resolve underlying problems that contributed to the issue, according to NRC officials, it is highly unlikely

[3]The International Atomic Energy Agency, International Nuclear Safety Advisory Group, *Safety Culture* (Vienna, Austria: February 1991).

that this one issue would rise to a high enough level of significance for it to be noted under NRC's Reactor Oversight Process. Additionally, the procedure is dependant on the inspector being aware of, and having the capability to, identify issues or trends in the area of safety culture. According to NRC officials, inspectors are not trained in what to look for when assessing licensee safety culture because they are, by and large, nuclear engineers. While they may have an intuition that something is wrong, they may not know how to assess it in terms of safety culture.

Additional specific examples NRC cites for indirectly assessing a selected number of safety culture aspects have the following limitations:

- NRC's inspection procedure for assessing licensees' employee concerns program is not frequently used. According to NRC Region III officials, approval to conduct such an inspection must be given by the regional administrator and the justification for the inspection to be performed has to be based on a very high level of evidence that a problem exists. Because of this, these officials said that the inspection procedure has only been implemented twice in Region III.

- NRC's allegation program provides a way for individuals working at NRC-regulated plants and the public to provide safety and regulatory concerns directly to NRC. It is a reactive program by nature because it is dependent upon licensees' employees feeling free and able to come forward to NRC with information about potential licensee misconduct. While NRC follows up on those plants that have a much higher number of allegations than other plants to determine what actions licensees are taking to address any trends in the nature of the allegations, the number of allegations may not always provide an indication of a poor safety culture, and in fact, may be the reverse. For example, the number of allegations at Davis-Besse prior to the discovery of the cavity in the reactor head in March 2002 was relatively small. Between 1997 and 2001, NRC received 10 allegations from individuals at the plant. In contrast, NRC received an average of 31 allegations per plant over the same 5-year period from individuals at other plants.

- NRC's lessons-learned reviews, such as the one conducted for Davis-Besse, are generally conducted when an incident having potentially serious safety consequences has already occurred.

- With respect to NRC's enforcement of employee protection regulations, NRC, under its current enforcement policy, would normally only take enforcement action when violations are of very significant or significant regulatory concern. This regulatory concern pertains to NRC's primary responsibility for ensuring safety and safeguards and protecting the environment. Examples of such violations would include the failure of a system designed to prevent a serious safety incident not working when it is needed, a licensed operator being inebriated while at the control of a nuclear reactor, and the failure to obtain prior NRC approval for a license change that has implications for safety. If violations of employee protection regulations do not pose very significant or significant safety, safeguards, or environmental concerns, NRC may consider such violations minor. In such cases, NRC would not normally document such violations in inspection reports or records, and would not take enforcement action.

- NRC's Reactor Oversight Process, instituted in April 2000, focuses on seven specific "cornerstones" that support the safety of plant operations to ensure reactor safety, radiation safety, and security. These cornerstones are: (1) the occurrence of operations and events that could lead to a possible accident if safety systems did not work, (2) the ability of safety systems to function as intended, (3) the integrity of the three safety barriers, (4) the effectiveness of emergency preparedness, (5) the effectiveness of occupational radiation safety, (6) the ability to protect the public from radioactive releases, and (7) the ability to physically protect the plant. NRC's process also includes three elements that cut across these seven cornerstones: (1) human performance, (2) a licensee's safety-conscious work environment, and (3) problem identification and resolution. NRC assumes that problems in any of these three crosscutting areas will be evidenced in one or more of the seven cornerstones in advance of any serious compromise in the safety of a plant. However, as evidenced by the Davis-Besse incident, this assumption has not proved to be true.

NRC also cites lessons-learned task force recommendations to improve NRC's ability to detect problems in licensee's safety culture, as a means to achieve our recommendation to directly assess licensee safety culture. These lessons-learned task force recommendations include (1) developing inspection guidance to assess the effect that a licensee's fuel outage shutdown schedule has on the scope of work conducted during a shutdown; (2) revising inspection guidance to provide for assessing the safety implications of long-standing, unresolved problems; corrective actions being phased in over the course of several years or refueling outages; and deferred plant modifications; (3) revising the problem identification and resolution inspection approach and guidance; and (4) reviewing the range of NRC's inspections and assessment processes and other NRC programs to determine whether they are sufficient to identify and dispose of the types of problems experienced at Davis-Besse. While we commend these recommendations, we do not believe that revising such guidance will necessarily alert NRC inspectors to early declines in licensee safety culture before they result in negative safety outcomes. Further, because of the nature of NRC's process for determining the relative safety significance of violations under NRC's new Reactor Oversight Process, we do not believe that any indications of such declines will result in a cited violation.

6. We have revised the report to reflect that boron in the form of boric acid crystals is dissolved in the cooling water. (See p. 13.)

7. On page 41 of the report, we recognize that NRC also relied on information provided by FirstEnergy regarding the condition of the vessel head. For example, in developing its risk estimate, NRC credited FirstEnergy with a vessel head inspection conducted in 1996. However, NRC decided that the information provided by FirstEnergy documenting vessel head inspections in 1998 and 2000 was of such poor quality that it did not credit FirstEnergy with having conducted them. As a result, NRC's risk estimate was higher than had these inspections been given credit.

8. The statement made by the NRC regional branch chief was taken directly from NRC's Office of the Inspector General report on NRC's oversight of Davis-Besse during the April 2000 refueling outage.[4]

9. We agree that up until the Davis-Besse event, NRC had not concluded that boric acid corrosion was a high priority issue. We clarified the text of the report to reflect this comment. (See p. 25.)

[4]NRC, Office of the Inspector General, *NRC's Oversight of Davis-Besse during the April 2000 Refueling Outage* (Washington, D.C.: Oct. 17, 2003).

10. We agree that plant operators in France decided to replace their vessel heads in lieu of performing the extensive inspections instituted by the French regulatory authority. The report has been revised to add these details. (See p. 31.)

11. We agree that caked-on boron, in combination with leakage, could accelerate corrosion rates under certain conditions. However, even without caked-on boron, corrosion rates could be quite high. Westinghouse's 1987 report on the corrosive effects of boric acid leakage concluded that the general corrosion rate of carbon steel can be unacceptably high under conditions that can prevail when primary coolant leaks onto surfaces and concentrates at the temperatures that are found on reactor surfaces. In one series of tests that it performed, boric acid solutions corroded carbon steel at a rate of about 0.4 inches per month, or about 4.8 inches a year. This was irrespective of any caked-on boron. In 1987, as a result of that report and extensive boric acid corrosion found at two other nuclear reactors that year—Salem unit 2 and San Onofre unit 2—NRC concluded that a review of existing inspection programs may be warranted to ensure that adequate monitoring procedures are in place to detect boric acid leakage and corrosion before it can result in significant degradation of the reactor coolant pressure boundary. However, NRC did not take any additional action.

12. We agree that NRC has requirements and processes that provide a number of circumstances in which a plant shutdown would or could be required. We also recognize that there were no legal objections to the draft enforcement order to shut down the plant, and that the basis for not issuing the order was NRC's belief that the plant did not pose an unacceptable risk to public health and safety. The statement in our report that NRC is referring to is discussing one of these circumstances—the licensee's failure to meet NRC's technical specification—and whether NRC believed that it had enough proof that the technical specification was not being met. The statement is not discussing the basis for NRC issuing an enforcement order. We revised the report to clarify this point. (See p. 34.)

13. The basis for our statement that NRC staff concluded that the first safety principle was probably not met was its November 29, 2001, briefing to NRC's Executive Director's Office and its November 30, 2001, briefing to the NRC commissioners' technical assistants. These briefings, the basis for which are included in documented briefing

slides, took place shortly before NRC formally notified FirstEnergy on December 4, 2001, that it would accept its compromise shutdown date.

14. We are referring to the same document that NRC is referring to—NRC's December 3, 2002, response to FirstEnergy (NRC's ADAMS accession number ML023300539). The response consists of a 2-page transmittal letter and an 7.3-page enclosure. The 7.3-page enclosure is 3 pages of background and 4.3 pages of the agency's assessment. The assessment includes statements that the safety principles were met but does not provide an explanation of how NRC considered or weighed deterministic and probabilistic information in concluding that each of the safety factors were met. For example, NRC concluded that the likelihood of a loss-of-coolant accident was acceptably small because of the (1) staff's preliminary technical assessment for control rod drive mechanism cracking, (2) evidence of cracking found at other plants similar to Davis-Besse, (3) analytical work performed by NRC's research staff in support of the effort, and (4) information provided by FirstEnergy regarding past inspections at Davis-Besse. However, the assessment does not explain how these four pieces of information successfully demonstrated if and how each of the safety principles was met. The assessment also states that NRC examined the five safety principles, the fifth of which is the ability to monitor the effects of a risk-informed decision. The assessment is silent on whether this principle is met. However, in NRC's November 29, 2001, briefing to NRC's Executive Director's Office and in its November 30, 2001, briefing to the NRC commissioners' technical assistants, NRC concluded that this safety principle was not met. As noted above, NRC formally notified FirstEnergy on December 4, 2001, that it would accept FirstEnergy's February 16, 2002, shutdown date.

15. See comment 3. We do not agree that the report statements mischaracterize the facts. Rather, we are concerned that NRC is misusing basic quantitative mathematics. In addition, with regard to NRC's concept of an annual average change in the frequency of core damage, NRC stated that the agency averaged the frequency of core damage that would exist for the 7-week period of time (representing the period of time between December 31, 2001, and February 16, 2002) over the entire 1-year period, using the assumption that the frequency of core damage would be zero for the remainder of the year—February 17, 2002, to December 31, 2002. According to our consultants, this calculation *artificially* reduced NRC's risk estimate to a level that is acceptable under NRC's guidance. By this logic, our consultants stated,

risks can always be reduced by spreading them over time; by assuming another 10 years of plant operation (or even longer) NRC could find that its calculated "risks" are completely negligible. They further stated that NRC's approach is akin to arguing that an individual, who drives 100 miles per hour 10 percent of the time, with his car otherwise garaged, should not be cited because his time-average speed is only 10 miles per hour.

Further, our consultants concluded that the "annual-average" core damage frequency approach was also clearly unnecessary, since one need only convert a core damage frequency to a core damage probability to handle part-year cases like the Davis-Besse case. Lastly, we find no basis for the calculation in any NRC guidance. According to our consultants, this new interpretation of NRC's guidance is at best unusual and certainly is inconsistent with NRC's guidelines regarding the use of an incremental core damage frequency. This interpretation also reinforces our consultants' impression that perhaps there was, in November 2001 and possibly is still today, some confusion among the NRC staff regarding basic quantitative metrics that should be considered in evaluating regulatory and safety issues. As noted in comment 3, we found no evidence of this calculation prior to February 2004.

16. While we agree that vessel head corrosion as extensive as later found at Davis-Besse was not anticipated, NRC had known that leakage of the primary coolant from a through-wall crack could cause boric acid corrosion of the vessel head, as evidenced by the Westinghouse work cited above. Regardless of information provided to NRC by individual licensees, such as FirstEnergy, NRC's model should account for known risks, including the potential for corrosion.

17. We agree that NRC was aware of control rod drive mechanism nozzle cracking at French nuclear power plants. NRC provided us additional information consisting of a December 15, 1994, internal memo, in which NRC concluded that primary coolant leakage from a through-wall crack could cause boric acid corrosion of the vessel head. However, because some analyses indicated that it would take at least 6 to 9 years before any corrosion would challenge the structural integrity of the head, NRC concluded that cracking was not a short-term safety issue. We revised the report to include this additional information. (See p. 40.)

18. See comment 15.

19. We agree that while not directly relevant to the Davis-Besse situation, NRC uses regulatory guide 1.177 to make decisions on whether certain equipment can be inoperable while a nuclear reactor is operating, which can pose very high instantaneous risks for very short periods of time. However, we include the reference to this particular guidance in the report because it was cited by an NRC official involved in the Davis-Besse decision-making process as another piece of guidance used in judging whether the risk that Davis-Besse posed was acceptable.

20. While regulatory guide 1.174 comprises 25 pages of guidance on how to use risk in making decisions on whether to allow license changes, it does not lay out how NRC staff are to use quantitative estimates of risk or probabilistic factors, or how robust these estimates must be in order to be considered along with more deterministic factors. The regulatory guide, which was first issued in mid-1998, had been in effect for only about 1.5 years when NRC staff was tasked with making their decision on Davis-Besse. According to the Deputy Executive Director of Nuclear Reactor Programs at the time the decision was being made, the agency was trying to bring the staff through the risk-informed decision-making process because Davis-Besse was a learning tool. He further stated that it was really the first time the agency had used the risk-informed decision-making process on operational decisions as opposed to programmatic decisions for licensing. At the time the decision was made, and currently, NRC has no guidance or criteria for use in assessing the quality of risk estimates or clear guidance or criteria for how risk estimates are to be weighed against other risk factors.

21. The December 3, 2002, safety assessment or evaluation did state that the estimated increase in core damage frequency was consistent with NRC's regulatory guidelines. However, as noted in comment 3, we disagree with this conclusion. In addition, while we agree that NRC has staff with risk assessment disciplines, we found no reference to these staff in NRC's safety evaluation. We also found no reference to NRC's statement that these staff gave more weight to deterministic factors in arriving at the agency's decision. While we endorse NRC's consideration of deterministic as well as probabilistic factors and the use of a risk-informed decision-making process, we continue to maintain that NRC needs clear guidance and criteria for the quality of risk estimates, standards of evidence, and how to apply deterministic as well as probabilistic factors in plant shutdown decisions. As the agency continues to incorporate a risk-informed process into much of its regulatory guidance and programs, such criteria will be increasingly

important when making shutdown as well as other types of decisions regarding nuclear power plants.

22. The information that NRC provided us indicates that completion dates for 2 of the 22 high priority recommendations have slipped.[5] One, the completion date for encouraging the American Society of Mechanical Engineers to revise vessel head penetration nozzle inspection requirements or, alternatively, for revising NRC's regulations for vessel head inspections has slipped from June 2004 to June 2006. Two, the completion date for assessing NRC's requirements that licensees have procedures for responding to plant leakage alarms to determine if the requirements are sufficient for identifying reactor coolant pressure boundary leakage has slipped from March 2004 to March 2005.

23. We agree with this comment and have revised the report to reflect this clarification. (See p. 49.)

24. Our estimate of at least an additional 200 hours of inspection per reactor per year is based on:

    - NRC's new requirement that its resident inspectors review all licensee corrective action items on a daily basis (approximately 30 minutes per day). Given that reactors are intended to operate continuously throughout the year, this results in about 3.5 hours per week for reviewing corrective action items, or about 182 hours per year. In addition, resident inspections are now required to determine, on a semi-annual basis, whether such corrective action items reflect any trends in licensee performance (16 to 24 hours per year). The total increase for these new requirements is about 198 to 206 hours per reactor per year.

    - A new NRC requirement that its resident inspectors validate that licensees comply with additional inspection commitments made in response to NRC's 2002 generic bulletin regarding reactor pressure vessel head and vessel head penetration nozzles. This requirement results in an additional 15 to 50 hours per reactor per fuel outage.

[5]Of NRC's 21 high priority recommendations, we categorized 1 recommendation as 2 so that we could better track actions taken to implement it. Thus, we have 22 recommendations categorized as high priority.

25. Our draft report included a discussion that NRC management's failure to recognize the scope or breadth of actions and resources necessary to fully implement task force recommendations could adversely affect how effective the actions may be. We made this statement based on NRC's initial response to the Office of the Inspector General's October 2003 report on Davis-Besse.[6] That report concluded that ineffective communication within NRC's Region III and between Region III and NRC headquarters contributed to the Davis-Besse incident. NRC, in its January 2004 response to the report, stated that among other things, it had developed training on boric acid corrosion and revised its inspection program to require semi-annual trend reviews. In February 2004, the Office of the Inspector General criticized NRC for limiting the agency's efforts in responding to its findings. Specifically, it stated that NRC did not address underlying and generic communication failures identified in the Office's report. In response to the criticism, on April 19, 2004 (while our draft report was with NRC for review and comment), NRC provided the Office of the Inspector General with additional information to demonstrate that its actions to improve communication within the agency were broader than indicated in the agency's January 2004 response. Based on NRC's April 19, 2004, response and the Office's agreement that NRC's actions appropriately address its concerns about communication within the agency, we deleted this discussion in the report.

26. We recognize that the lessons-learned task force did not make a recommendation for improving the agency's decision-making process because the task force coordinated with the Office of the Inspector General regarding the scope of their respective review activities and because the task force was primarily charged with determining why the vessel head degradation was not prevented. (See p. 55.)

27. We agree that NRC's December 3, 2002, documentation of its decision was prepared in response to a finding by the Davis-Besse lessons-learned task force. We revised our report to incorporate this fact. (See p. 55.)

28. We agree that NRC's lessons-learned task force conducted a preliminary review of reports from previous lessons-learned task forces

[6] NRC, Office of the Inspector General, *NRC's Oversight of Davis-Besse during the 2000 Refueling Outage* (Washington, D.C.: Oct. 17, 2003).

and, as a result of that review, made a recommendation that the agency perform a more detailed effectiveness review of the actions taken in response to those reviews. We revised the report to reflect that NRC's detailed review is currently underway. (See p. 55.)

GAO Contacts and Staff Acknowledgments

GAO Contacts

Jim Wells, (202) 512-3841
Ray Smith, (202) 512-6551

Staff Acknowledgments

In addition, Heather L. Barker, David L. Brack, William F. Fenzel, Michael L. Krafve, William J. Lanouette, Marcia Brouns McWreath, Judy K. Pagano, Keith A. Rhodes, and Carol Hernstadt Shulman made key contributions to this report.

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Exhibit A

EXHIBIT "A"

UNITED STATES
NUCLEAR REGULATORY COMMISSION

In the matter of

ENTERGY NUCLEAR INDIAN POINT 2, L.L.C. **ENTERGY NUCLEAR INDIAN POINT 3, L.L.C.**	)	**LicenseNo. DPR-26 &DPR 64**
Indian Point Energy Center Unit 2 & **Indian Point Energy Center 3** **Entergy Nuclear Operations, Inc.**	)	**Docket No. 50-247 & No. 50-286**
License Renewal Application	)	**ASLBP No. 70-858-03-LR-BD01**

DECLARATION OF RICHARD L. BRODSKY

Richard L. Brodsky represents the 92nd Assembly District, which includes the Towns of Greenburgh and Mount Pleasant, the Villages of Ardsley, Dobbs Ferry, Elmsford, Hastings-on-Hudson, Irvington, Pleasantville, Sleepy Hollow, Tarrytown, a portion of the Village of Briarcliff Manor, and part of the City of Yonkers.

Assemblyman Brodsky has led efforts to investigate the Indian Point nuclear power plants, undertook the first independent analysis of the Evacuation Plans for Indian Point, and in February 2002, he released the Interim Report on the Evacuation Plans for the Indian Point Nuclear Generating Facility, which detailed the serious and systematic deficiencies which make it unable to "adequately protect the public health and safety," as required by law.

These findings were confirmed by the James Lee Witt Report released eleven months later. On June 13, 2002, Chairman Brodsky, along with numerous local, State, and federal elected officials, submitted a formal Petition to the Federal Emergency Management Agency requesting that they withdraw their approval of the Indian Point Evacuation Plans, marking the first formal challenge to a nuclear plant's evacuation plans.

He is also the lead Petitioner and Counsel, along with the Hudson River Sloop Clearwater, Pete and Toshi Seeger and others, in successful litigation seeking to compel the State Department of Environmental Conservation to effectively regulate the ongoing pollution of the Hudson River caused by Indian Point's intake of over two billion gallons of water daily.

He serves as Chairman of the Standing Committee on Corporations, Authorities, and Commissions, which oversees the state's public and private corporations. This includes jurisdiction over business corporation law and telecommunications, as well as all public authorities, such as the MTA, the Thruway Authority, the Public Service Commission, the Port Authority, and the Lower Manhattan Development Corporation.

From 1993 to 2002, Assemblyman Brodsky served as Chairman of the Committee on Environmental Conservation, where he structured the most dramatic legislative advances in environmental conservation in over two decades. His accomplishments include authoring the legislation that created the Environmental Protection Fund, the first dedicated fund for environmental protection in the history of New York State, and the Clean Air/Clean Water Bond Act, a $1.75 billion bond act passed by voters across New York to provide a funding mechanism for unfunded clean air and clean water projects throughout the State.

He lives within 15 miles of the plant in Elmsford , New York with his wife and two daughters.

I declare under penalty of perjury that the foregoing is true and correct.

Executed this 10th day of December, 2007, at Elmsford, NY.

Richard L. Brodsky

State of New York)
)ss.:
County of Westchester)

On the 10th day of December, in the year 2007 before me, the undersigned, personally appeared RICHARD BRODSKY, 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.

Notary Public

11

EXHIBIT B

Exhibit "B"

UNITED STATES_NUCLEAR REGULATORY COMMISSION

In the matter of

ENTERGY NUCLEAR INDIAN POINT 2, L.L.C.
ENTERGY NUCLEAR INDIAN POINT 3, LLC
ENTERGY NUCLEAR OPERATIONS, LCC
Indian Point Energy Center Unit 2 & Indian Point Entergy Center Unit 3

LicenseNo. DPR-26 & DPR 64

) Docket No. 50-247 & No. 50-286

License Renewal Application

DECLARATION OF ALLEGRA DENGLER

My name is Allegra Dengler . I live with my husband at 60 Judson Avenue, Dobbs Ferry, NY, 10522. We live approximately 18.5 miles from Indian Point. I am a member of the Sierra Club LHG and have served as Conservation Chair and Co-Chair of the group. I served four years as Trustee of the Village of Dobbs Ferry, and in that capacity participated in the many hearings about the adequacy of the emergency evacuation plans during the study by Witt Associates for the State of New York.

The Sierra Club represents my interests in a Petition to Intervene, Request for Hearing and Contentions and the Notice of Appearance, in the matter of Entergy Nuclear Indian Point 2 LLC and Indian Point 3 LLC, and Entergy Nuclear Operations, Inc. License Renewal Application.

I have lived in Dobbs Ferry since 1987. On September 11, 2001, I became acutely aware of how close Indian Pt was to Dobbs Ferry when I learned that one of the fateful planes of that day had flown over Indian Pt. Later it was revealed that terrorists had considered striking Indian Pt instead of the World Trade Center,

I spend time on the river canoeing. I spend many days at our waterfront park walking, taking in the sunset or attending our summer jazz concerts , which are very popular. There are many other events at our waterfront park on the banks of the Hudson, like auto shows and the American Legion Flea Mkt which I also attend, I served on the Village's Waterfront Committee to increase public use of the park and preserve part as natural area. As a Village Trustee, I chaired the Land Use Committee which shepherded the LWRP Local Waterfront Revitalization Plan through the approval process and it has been adopted by the Village.

As a Village Trustee I was well aware that any discharge into the river requires a permit to protect the river. I am very disturbed that Indian Pt can continue to discharge heated water into the Hudson River without any permit at all. This is unacceptable. I can't dump anything out of my canoe, and as a resident I can't dump anything toxic into village drains, but Indian Pt has been allowed to discharge heated water into the river year-after year. Recently it has been discovered that Indian Pt has ongoing releases of radioactive materials into the ground, which are migrating into the Hudson. Additionally, their intake valves filter and kill millions of fish and other river life year after year. Shad is our last commercial fish in the Hudson, and the shad runs in the Hudson are decreasing to such an extent that the future of the species is at risk. Yet year after year Indian Pt minces them up in its intake valves and disturbs their development with heated water.

It is clear to me that for all of the above reasons Indian Point should be closed. I declare that the statements made in this declaration are true and correct to the best of my knowledge.

Executed this 30th day of January, 2008 at Dobbs Ferry, New York.

Allegra Dengler Allegra Dengler

State of New York)
)ss.:
County of Westchester)

On the 30 day of JANUARY in the year 2008 before me, the undersigned, personally appeared ALLEGRA DENGLER , 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.

Laurence G. Dengler
Notary Public

LAURENCE G. DENGLER
Notary Public, State of New York
No 60-01DE0920075
Qualified in Westchester County
Commission Expires December 31, 2009

UNITED STATES
NUCLEAR REGULATORY COMMISSION

In the matter of

ENTERGY NUCLEAR INDIAN POINT 2, L.L.C.		**LicenseNo.**
ENTERGY NUCLEAR INDIAN POINT 3, LLC	**)**	**DPR-26 &**
ENTERGY NUCLEAR OPERATIONS, LCC		**DPR 64**
Indian Point Energy Center Unit 2 & Indian Point	**)**	**Docket**
Entergy Center Unit 3		**No. 50-247**
		& No. 50-
		286

License Renewal Application

DECLARATION OF JOANNE STEELE

My name is Joanne Steele. I live 50 miles from Indian Point and I own property with a building permit in progress in Ulster Park, 47 miles from Indian Point.

Sierra Club represents my interests. I am Secretary of The Mid-Hudson Group of the Atlantic Chapler of the Sierra Club.

I am an avid Kayaker on The Hudson River, in particular South of Ulster Park: Newburgh, Croton, etc. We need no further danger from Indian Point. I am against the relisencing of any and all of Indian Point Nuclear plants. Thank you.

Sincerely,

Joanne Steele

Joanne Steele

State of New York }
County of Ulster } ss.:

On the 31st day of January in the year 2008 before me, the undersigned, a notary public in and for said state, personally appeared Joanne Steele, 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 signature(s) on the instrument, the individual(s), or the person upon behalf of which the individual(s) acted, executed the instrument.

Jennafer Romanczuk

Notary Public

JENNAFER ROMANCZUK
Notary Public, State of New York
Reg. 01RO6147225
Qualified in Dutchess County
Commission Expires May 30, 2010

UNITED STATES
NUCLEAR REGULATORY COMMISSION

In the matter of

ENTERGY NUCLEAR INDIAN POINT 2, L.L.C.		**License No.**
ENTERGY NUCLEAR INDIAN POINT 3, LLC	**)**	**DPR-26 &**
ENTERGY NUCLEAR OPERATIONS, LCC		**DPR 64**
Indian Point Energy Center Unit 2 & Indian Point	**)**	**Docket**
Entergy Center Unit 3		**No. 50-247**
		& No. 50-
		286

License Renewal Application

DECLARATION OF JOHN GEBHARDS

My name is John Gebhards; I live at 48 Wintergreen Ave., Newburgh, New York, 12550. Newburgh is located just up stream approximately 20 miles from the Indian Point power plant. I am a member of the Ramapo/Catskill Group, Atlantic Chapter of the Sierra Club. I have lived in Orange County, NY within 25 miles of the Indian Point power plant since 1982. The Hudson River is a historical and natural scenic treasure in our back yard.

The Sierra Club represents my interests in a Petition to Intervene, Request for Hearing and Contentions and the Notice of Appearance, in the matter of Entergy Nuclear Indian Point 2 LLC and Indian Point 3 LLC, and Entergy Nuclear Operations, Inc. License Renewal Application.

I often lead canoe or kayak trips on the Hudson River, often launching from the NYS DEC operated Kowawese Park in the Town of New Windsor. I participate in many cultural events and activities which are centered around the Hudson River such as Earth Day celebrations, Shad Bake fests, the Beacon Sloop Club from the Strawberry Fest in June through the Pumpkin Fest in the fall, the Swim Across the Hudson to support the creation of a in-river swimming pool at Beacon, the Great Hudson River Revival and many other river front festivals.

I am very concerned about the aging condition of these plants and the reported occasional leaks. Their location in a highly densely populated area make evacuation in the case of an emergency logistically impossible. Their proximity to our nation's premier military academy, West Point, and one of our nation's finest cities, New York, makes the potential either an accidental release or a terrorist provoked release of grave concern.

I feel that it is not prudent to reauthorize the operation of these aging Indian Point nuclear plants. I declare that the statements made in this declaration are true and correct to the best of my knowledge.

Executed this 31st day of January, 2008 at Newburgh, New York.

John Gebhards ____________ John Gebhards

State of New York)
)ss.:
County of Orange)

On the 31 day of JANUARY, in the year 2008 before me, the undersigned, personally appeared JOHN GEBHARDS, 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.

____
Notary Public

ANDREW J. ZARUTSKIE
Notary Public, State Of New York
No. 01ZA4502524
Qualified in Orange County
Commission Expires Nov. 30, 2009

UNITED STATES
NUCLEAR REGULATORY COMMISSION

In the matter of

ENTERGY NUCLEAR INDIAN POINT 2, L.L.C.		**License No.**
ENTERGY NUCLEAR INDIAN POINT 3, LLC	)	**DPR-26 &**
ENTERGY NUCLEAR OPERATIONS, LCC		**DPR 64**
Indian Point Energy Center Unit 2 & Indian Point	)	**Docket**
Entergy Center Unit 3		**No. 50-247**
		& No. 50-
		286

License Renewal Application

DECLARATION OF Diana Krautter

My name is Diana Krautter and I currently live at 48 Wintergreen Avenue in Newburgh, New York. I have lived in both Rockland and Orange County over 30 years within a distance of approximately 20 miles from Indian Point. I am the Membership Chair of the Sierra Ramapo/Catskill Group of the Atlanta Chapter and organize and participate in many kayaking adventures on the Hudson River as well as participate in numerous activities along its banks.

The Sierra Club represents my interests in a Petition to Intervene, Request for Hearing and Contentions and the Notice of Appearance, in the matter of Entergy Nuclear Indian Point 2 LLC and Indian Point 3 LLC, and Entergy Nuclear Operations, Inc. License Renewal Application.

Each year I see an increasing number of kayakers enjoying the waters of the Hudson. There is nothing I like better than introducing newcomers to this wonderful river from Manhattan to Albany.

One of my very favorite places is at Kowawese Unique Park in New Windsor, NY where I spend countless hours along the shore and on the Hudson picking up and dragging home all sizes of driftwood. And, I can never get enough of its scenic view of Bannerman Island, the hills above Beacon and its ever-changing shore line of weathered wood. Even the

Moodna Creek which flows into the Hudson is affected by its tides making each paddle up the creek an adventure. Wildlife and fauna abound along the Hudson and its tributaries.

We must protect all the species that inhabit the waters, its shores and its towns and cities from ever increasing harm. Indian Pont is one of our biggest threats. We cannot tolerate and must end the on-going hazards and its potential deadly components of Indian Point.

Executed this 31st day of January, 2008 at Newburgh, New York.

Diana Krautter ____________________ Diana Krautter

State of New York)
)ss.:
County of ~~Rockland~~ ORANGE)

On the 31 day of JANUARY, in the year 2008 before me, the undersigned, personally appeared DIANA KRAUTTER, 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.

____
Notary Public

ANDREW J. ZARUTSKIE
Notary Public, State Of New York
No. 01ZA4502524
Qualified in Orange County
Commission Expires Nov. 30, 2009

UNITED STATES
NUCLEAR REGULATORY COMMISSION

In the matter of

ENTERGY NUCLEAR INDIAN POINT 2, L.L.C.		**LicenseNo.**
ENTERGY NUCLEAR INDIAN POINT 3, LLC	**)**	**DPR-26 &**
ENTERGY NUCLEAR OPERATIONS, LCC		**DPR 64**
Indian Point Energy Center Unit 2 & Indian Point	**)**	**Docket**
Entergy Center Unit 3		**No. 50-247**
		& No. 50-286

License Renewal Application

DECLARATION OF GEORGE KLEIN

My name is George Klein, I live at 74 Croton Dam Road, Ossining, NY 10562. I live approximately 10 miles from Indian Point. I am a member of the Sierra Club, and the chairman of the Sierra Club, Lower Hudson Group, representing about 5,000 members in Westchester, Putnam and Rockland counties. The Lower Hudson Group is one of 11 local groups of the Sierra Club, Atlantic Chapter, which is the New York State chapter.

The Sierra Club, Atlantic Chapter represents my interests in a Petition to Intervene, Request for Hearing and Contentions and the Notice of Appearance, in the matter of Entergy Nuclear Indian Point 2 LLC and Indian Point 3 LLC, and Entergy Nuclear Operations, Inc. License Renewal Application.

I have lived in the Hudson Valley since 1993 in locations such as New York City, Mount Kisco, New Castle and Ossining, New York.

I oppose the relicensing by NRC of any reactors at Indian Point, which is leaking radioactive waste into the local groundwater. Why allow Indian Point to continue leaking for another 20 years? This is a huge danger for public health and for the environment.

The evacuation plan is unworkable, and no locally responsible parties have approved it.

The ongoing buildup of spent fuel rods is another concern. They are a current danger, and one that increases every year. Everyone knows that they are a terrorist target. Why would we, as an intelligent society, increase the attractiveness of this as a terrorist target?

The increase in water temperature caused by using the Hudson River as a vast heat sink for Indian Point is another problem.

We do not need the electrical energy produced by Indian Point, and would rather get our energy from non-nuclear sources.

It is clear to me that for all of the above reasons Indian Point should be closed. I declare that the statements made in this declaration are true and correct to the best of my knowledge.

Executed this 31 day of January, 2008 at Ossining, New York.

George Klein

State of New York)
)ss.:
County of Westchester)

On the 31 day of JANUARY, in the year 2008 before me, the undersigned, personally appeared GEORGE KLEIN, 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.

Notary Public

BERNARD HERRERA
Notary Public, State of New York
No. 01HE6144371
Qualified in Westchester County
My Commission Expires 4/24/10

Exhibit C

Exhibit "C"

United States General Accounting Office

GAO

Report to the Honorable
Edward J. Markey,
House of Representatives

December 2001

NUCLEAR REGULATION

NRC's Assurances of Decommissioning Funding During Utility Restructuring Could Be Improved

G A O

Accountability * Integrity * Reliability

GAO-02-48

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Abbreviations

ALARA	as-low-as-reasonably-achievable
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
DOE	Department of Energy
EPA	Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAO	General Accounting Office
GTCC	Greater Than Class C (waste)
NRC	Nuclear Regulatory Commission
PECO	PECO Energy Company (formerly, Philadelphia Electric Company)
PSEG	Public Service Electric and Gas Company
PUC	Public Utility Commission

GAO

Accountability * Integrity * Reliability

United States General Accounting Office
Washington, DC 20548

December 3, 2001

The Honorable Edward J. Markey
House of Representatives

Dear Mr. Markey:

This report responds to your request that we review how the Nuclear Regulatory Commission ensures, in a period of economic deregulation and restructuring of the electricity industry, that sufficient funds will be available to decommission nuclear power plants after the plants are permanently shut down.

Unless you publicly announce its contents earlier, we plan no further distribution of this report until 30 days after the date of this letter. At that time, we will send copies to the appropriate congressional committees; the Chairman, Nuclear Regulatory Commission; and the Director, Office of Management and Budget. We will also make copies available to others upon request.

Please contact me at (202) 512-3841 if you or your staff have any questions about this report. Key contributors to this report are listed in appendix II.

Sincerely yours,

Gary L. Jones

(Ms.) Gary L. Jones
Director, Natural Resources
and Environment

Executive Summary

The Nuclear Regulatory Commission (NRC) has licensed 125 commercial nuclear power plants to operate in the United States, each for a finite number of years. For safety reasons, after a licensee retires a plant, the licensee must eventually dismantle it. The spent (used) fuel is removed from the nuclear reactor and usually stored at the plant site until the fuel can be removed for disposal. The other radioactive wastes from dismantling the plant are shipped to one or more off-site disposal facilities. Upon completion of this process, called "decommissioning," the plant site can be reused for other purposes.

The costs of decommissioning, which vary according to the size of the plant and the level of contamination, generally fall within the range of $300 million to $400 million per plant. To ensure the availability of adequate funds to pay for this process, NRC requires its licensees to select a method or combination of methods for financing future decommissioning activities from among the acceptable methods specified in its regulations.

Traditionally, plant owners amass decommissioning funds through charges imbedded in predetermined electricity rates, which state utility commissions and/or the Federal Energy Regulatory Commission regulate. However, with the deregulation of the electric utility industry in many states, a competitive market instead of regulated rates now determines the price that some plant owners can charge for producing electricity. Consequently, these plant owners can no longer collect decommissioning funds through the traditional method.

Deregulation has led many states and their electric utilities to restructure much of their electricity industry to separate the producers of electricity from those who transmit and distribute (sell) electricity to customers. As part of this restructuring, the ownership and/or operation of plants has changed for more than half of the nuclear power plants in the United States. Since 1998, for example, utilities that own all or part of eight nuclear plants have contracted the operation of these plants to other companies. And other utilities have sold or are in the process of selling all or part of 15 plants. Finally, the reorganizations and mergers of electric utilities have resulted in the transfer of licenses for more than 30 plants to companies formed specifically to produce electricity. The number of these transfers highlights the importance of NRC's regulatory role in ensuring that new licensees are financially qualified to operate, maintain, and eventually decommission these plants. The transfers also underscore the need for consistent financial disclosure of decommissioning liabilities to the potential investors in new companies formed, at least in part, to produce electricity from nuclear power plants.

Concerned about the adequacy of decommissioning funds, particularly in deregulated markets, Representative Edward Markey asked GAO to determine how (1) transfers of licenses to operate or own nuclear power plants have affected assurances that adequate funds will be available to operate and decommission these plants, (2) various site cleanup standards and proposed new decommissioning methods affect projected decommissioning costs, and (3) changes in financial reporting standards affect the disclosure and funding of decommissioning liabilities.

Background

Before transferring a license to a new plant owner, NRC requires the prospective owner to demonstrate that it has both the technical ability and financial backing to safely own and operate the plant. NRC also requires owners to demonstrate that they will accumulate a prescribed minimum amount of funds to pay for the eventual decommissioning of their plants. Owners must ensure that these funds will be available by choosing one or a combination of the following options:

- periodic deposits (at least annually) into a trust fund outside of the owner's control;
- prepayment of the entire estimated decommissioning liability into a trust fund outside of the owner's control;
- obtaining a surety bond, insurance, letter of credit, or line of credit payable to a trust established for decommissioning costs; or
- guaranteeing the payment of decommissioning costs, provided that the guarantor (usually an affiliate or parent company to the owner) passes specific financial tests.

Until recently, essentially all plant owners chose to accumulate decommissioning funds through periodic deposits. However, in September 1998, NRC amended its regulations to restrict the use of this option in deregulated markets. Under the amended regulations, owners may rely on periodic deposits only to the extent that those deposits are guaranteed through regulated rates charged to consumers. In conjunction, NRC has issued written procedures, called a "standard review plan", describing how its staff should determine the adequacy of a prospective owner's financial qualifications to operate its plant(s) and its proposed method(s) for assuring the availability of funds to eventually decommission the plant(s).

To estimate future decommissioning costs, plant owners may use a mathematical formula that is provided in NRC's regulations or a site-specific estimate, if the costs developed from it are higher. The formula assumes that plant sites will be cleaned up in compliance with NRC's standards. By the time that a plant is decommissioned, however, other cleanup standards could apply. For example, the Environmental Protection Agency (EPA) has more restrictive cleanup standards that could, in some circumstances, be applied to a nuclear power plant site, and some states are establishing cleanup standards for decommissioning nuclear power plants and/or other nuclear facilities.

Results in Brief

In most of the requests to transfer licenses to own or operate nuclear power plants that NRC has approved, the financial arrangements have either maintained or enhanced the assurance that adequate funds will be available to decommission those plants. Owners relying on outside companies to operate their plants have retained the responsibility for financing the future decommissioning of these plants and continue to collect funds for this purpose through their economically regulated sales of electricity. When new owners purchased all or parts of 15 plants from utility companies, the level of assurance was enhanced through the prepayment of the decommissioning trust funds and guarantees from affiliate or parent companies to pay any remaining decommissioning costs. However, when new owners proposed to continue relying on periodic deposits to external sinking funds, NRC's reviews were not always rigorous enough to ensure that decommissioning funds would be adequate. Moreover, NRC did not always adequately verify the new owners' financial qualifications to safely own and operate the plants. Accordingly, GAO is making a recommendation to ensure a more consistent review process for license transfer requests.

Varying cleanup standards and proposed new decommissioning methods introduce additional uncertainty about the costs of decommissioning nuclear power plants in the future. Plants decommissioned in compliance with NRC's requirements may, under certain conditions, also have to meet, at higher cost, more stringent EPA or state standards. New decommissioning methods being considered by NRC, which involve leaving more radioactive waste on-site, could reduce short-term decommissioning costs yet increase costs over the longer term. Moreover, they would raise significant technical and policy issues concerning the disposal of low-level radioactive waste at plant sites instead of in regulated disposal facilities. Adding to cost uncertainty, NRC allows plant owners to wait until 2 years before their license is terminated—relatively late in the decommissioning process—to perform overall radiological assessments to determine whether any residual radiation anywhere at the site will need further clean-up in order to meet NRC's site release standards. Accordingly, GAO is recommending that NRC reconcile its proposed decommissioning methods with existing waste disposal regulations and policies and require licensees to assess their plant sites for contamination earlier in the decommissioning process.

Changes to the Financial Accounting Standards Board's financial reporting standard will require, for the first time, owners of facilities that require significant end-of-life cleanup expenditures—such as nuclear power plants—to consistently report estimated decommissioning costs as liabilities in their financial statements. When this standard takes effect in mid-2002, many companies that are licensed by NRC to own nuclear power plants will have to change their current financial-reporting practices, and the reporting of estimated decommissioning costs will become more uniform. However, the new accounting standard is not intended to, and will not, establish a legal requirement that these licensees set aside adequate funding for decommissioning costs.

Principal Findings

Effect of License Transfers on Decommissioning Funding

The level of assurance that adequate decommissioning funds will be available when licensees retire nuclear power plants has remained the same or increased for most of the license transfers that NRC has reviewed and approved. When plant owners contracted out the operation of their plants, NRC required the owners to continue collecting decommissioning funds through their regulated electricity rates, thus maintaining the previous level of assurance. When NRC reviewed and approved the sale of all or parts of 15 plants to new generating companies, the level of assurance was enhanced because the selling utilities generally prepaid the projected decommissioning funds. To the extent that a few decommissioning trust funds were not fully prepaid, either the selling utility or the new owners' affiliated or parent companies provided additional guarantees consistent with NRC's requirements.

In instances when new owners continued to rely on periodic deposits to the transferred trust funds, however, NRC's review process did not consistently result in the same level of assurance that decommissioning funds would be adequate when the owners' plants shut down. For example, when a new company formed through a merger applied to transfer the licenses for the ownership of all or parts of 20 plants, including 4 retired plants, NRC did not verify whether there were contractual arrangements to transfer the decommissioning funds collected for the plants into the trust funds for those plants. Also, for the four plants that had permanently shut down, NRC did not request that the new owner (1) provide any more information on the status or plans for these prematurely shut down plants than it had for the 16 plants that were operating or (2) demonstrate how the owner planned to acquire the additional decommissioning funds as it had for another retired plant.

For the most part, 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. However, NRC did not obtain the same degree of financial assurance in the case of one merger that created a new generating company that is now responsible for owning, operating, and decommissioning the largest fleet of nuclear plants in the United States. This new owner did not provide, and NRC did not request, guaranteed additional sources of revenue above the market sale of its electricity, as other new owners had. Moreover, NRC did not document its review of the financial information—including revenue projections, which were inaccurate—that the new owner submitted to justify its qualifications to safely own and operate 16 plants.

Effect of Regulatory Policies on Decommissioning Costs

Varying radiation cleanup standards and the possibility that NRC will approve alternative decommissioning methods are two of the most significant factors that add uncertainty to estimates of future decommissioning costs. Depending on future circumstances, for example, plants decommissioned according to NRC's radiation cleanup standards could also have to meet more stringent EPA or state standards, potentially increasing the cost of decommissioning. EPA has indicated that if NRC does not tighten its standards, EPA could reconsider its policy of exempting decommissioned nuclear plant sites from the stricter cleanup standards that EPA enforces under the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (also known as CERCLA or Superfund). In addition, the states of Maine, Massachusetts, New York, and New Jersey have already adopted radiation cleanup standards stricter than NRC's, and more states may do so. These stricter standards will require plant owners to incur significant additional decommissioning costs; for example, officials from one plant estimate that

Maine's standard will add $25 million to $30 million to the decommissioning costs for that plant.

Alternative decommissioning methods under consideration for NRC's approval would have an unknown affect on overall decommissioning costs. Because the methods involve leaving more radioactive waste on-site—either buried as rubble or encased within the reactor containment structure—they would reduce the waste-disposal component of decommissioning costs. However, they could add considerably to long-term costs because of the need for extended institutional control of the sites. Moreover, these methods appear to conflict with NRC's technical requirements for licensing low-level radioactive waste disposal facilities. In addition, the proposed methods may run counter to the policy expressed in the Low-Level Radioactive Waste Policy Amendments Act, which encourages states to manage low-level radioactive wastes on a regional basis and to provide centralized disposal facilities.

Another potentially significant factor contributing to the uncertainty about decommissioning cost is the lack of information on the degree of contamination at some plant sites. NRC's decommissioning requirements allow plant owners to wait until 2 years before the proposed license termination date to perform an overall survey of their plant sites for radiation contamination. Postponing the survey until this late in the decommissioning process increases the risk that owners will incur unplanned cleanup expenses after significant portions of the available decommissioning funds have already been expended.

Disclosure of Liability for Decommissioning Costs

The Financial Accounting Standards Board has adopted a new financial reporting standard that, beginning in mid-2002, should result in more uniform reporting of decommissioning costs. Currently, companies disclose their liability for decommissioning costs using a number of different methods, making comparisons by investors difficult. Under the new standard, companies must report estimated decommissioning costs as liabilities in their financial statements, using a specified method to calculate the amount of the liability. However, the new standard applies not just to nuclear power plants but to other industries as well, and the method specified differs from the method that NRC requires for nuclear power plant licensees. The new standard will have no legal or regulatory affect on the actual accumulation of decommissioning funds and is not intended to do so.

Recommendations for Executive Action

To ensure that the decommissioning assurance methods and financial qualifications of all new plant owners are consistently verified, validated, and documented, GAO recommends that the Chairman, NRC, revise the Commission's standard review plan and related management controls for reviewing license transfers to include a checklist or step-by-step process for its staff, management, and prospective plant owners to follow.

GAO also recommends that the Chairman, NRC, amend the Commission's ongoing consideration of modifications to radiological criteria for terminating licenses and alternative decommissioning approaches to address

- how the burial or entombment of low-level radioactive waste at nuclear plant sites, leading to a potentially large number of contaminated sites scattered around the country, may affect the federal policy under the Low-Level Radioactive Waste Policy Act to manage radioactive waste on a regional basis, and
- concerns about whether these decommissioning approaches are technically compatible with provisions of the Low-Level Radioactive Waste Policy Act, the interstate compact agreements that implement the act, and NRC's technical regulations on licensing disposal facilities for low-level radioactive waste.

To reduce the likelihood that site contamination will go undetected until late in the cleanup process, GAO recommends that the Chairman, NRC, require licensees to survey their plant sites for radiation as soon as possible after the announcement of their intentions to permanently cease operations, rather than allowing them to wait until 2 years before decommissioning is supposed to be complete.

Agency Comments and GAO's Evaluation

GAO provided NRC with a draft of this report for review and comment. NRC said that GAO has provided constructive comments regarding documentation of the financial considerations associated with requests to transfer licenses for nuclear power plants. NRC also said it is concerned that GAO has not fully represented certain aspects of its review process for license transfers, nor entirely considered the various processes associated with the decommissioning of a nuclear plant. NRC provided specific comments on these matters, including reasons why, in some cases, it does not agree with GAO's recommendations. NRC's comments also, it said, supplied a more comprehensive perspective on our conclusions and recommendations. (NRC's comments are contained in app. I.)

Specifically, NRC disagreed that it should modify its review guidance to include a checklist or step-by-step process to be followed because many of the proposed license transfers are unique. GAO disagrees. Licensees have consistently used a few basic methods of providing decommissioning funding assurance. Revising the review guidance to ensure, on the basis of NRC's experiences to date, that each license transfer review is based on information that is consistent with other transfers that used similar methods of assurance could help NRC meet its goal of increasing its efficiency and effectiveness.

NRC also disagreed that it should address technical and policy issues associated with the potential on-site burial of radioactive waste from decommissioning nuclear plant sites because this waste would not be classified as low-level radioactive waste. GAO disagrees because it is difficult to discern why radioactive material buried on-site—material that has traditionally been shipped to disposal facilities designed and regulated for such purpose--does not merit the same protection as material sent to a low-level waste disposal site.

Finally, NRC disagreed that it should require licensees to make radiation surveys of their plant sites earlier because this proposed step would not add significant value to the decommissioning process. GAO disagrees, because plant employees most knowledgeable about historical plant operations and site conditions would more likely be available when a plant has been permanently shut down rather than later when decommissioning has been almost completed.

Chapter 1: Introduction

Nuclear power plants generate about 20 percent of electricity in the United States. At the time of this review, there were 103 of these plants in operation.[1] No new nuclear power plants have been ordered since 1978, however, and 22 plants that previously operated under licenses issued by the Nuclear Regulatory Commission (NRC) have been permanently shut down. The licenses for 45 additional plants will expire within the next 15 years. The owners of these plants, therefore, will have to choose whether to retire their plants or to seek license extensions from NRC for up to an additional 20 years.

Radioactive contamination lingers long after power plants are closed. To protect public health and safety, the amount of residual radioactivity present at the site of a retired nuclear power plant must be reduced through a process known as decommissioning. After the spent (used) fuel has been removed from the plant's reactor vessel, the plant must be dismantled and the radioactive wastes shipped to one or more disposal facilities for radioactive wastes.[2] The decommissioning process is still relatively new—3 of the 22 retired commercial nuclear power plants have been decommissioned, 6 other plants are being decommissioned, and 13 plants are awaiting decommissioning. The process is also costly. Experience to date shows that decommissioning costs anywhere from $300 million to $400 million or more, depending on factors, such as plant size, the extent of contamination, and waste disposal costs.

NRC and plant owners must balance public health and safety with the cost and technical logistics of the decommissioning process. Moreover, the relatively high cost of decommissioning a nuclear power plant makes the process an issue for economic regulators, such as the Federal Energy Regulatory Commission (FERC) and state public utility commissions (PUC's), and the electricity industry in the relatively new environment of deregulating and restructuring the electricity industry.

[1] These numbers do not include one plant—the Tennessee Valley Authority's Brown's Ferry Unit 1 plant—that is licensed to operate. That plant, however, has not operated since March 1985, has no fuel loaded, and cannot load fuel and restart without NRC's approval.

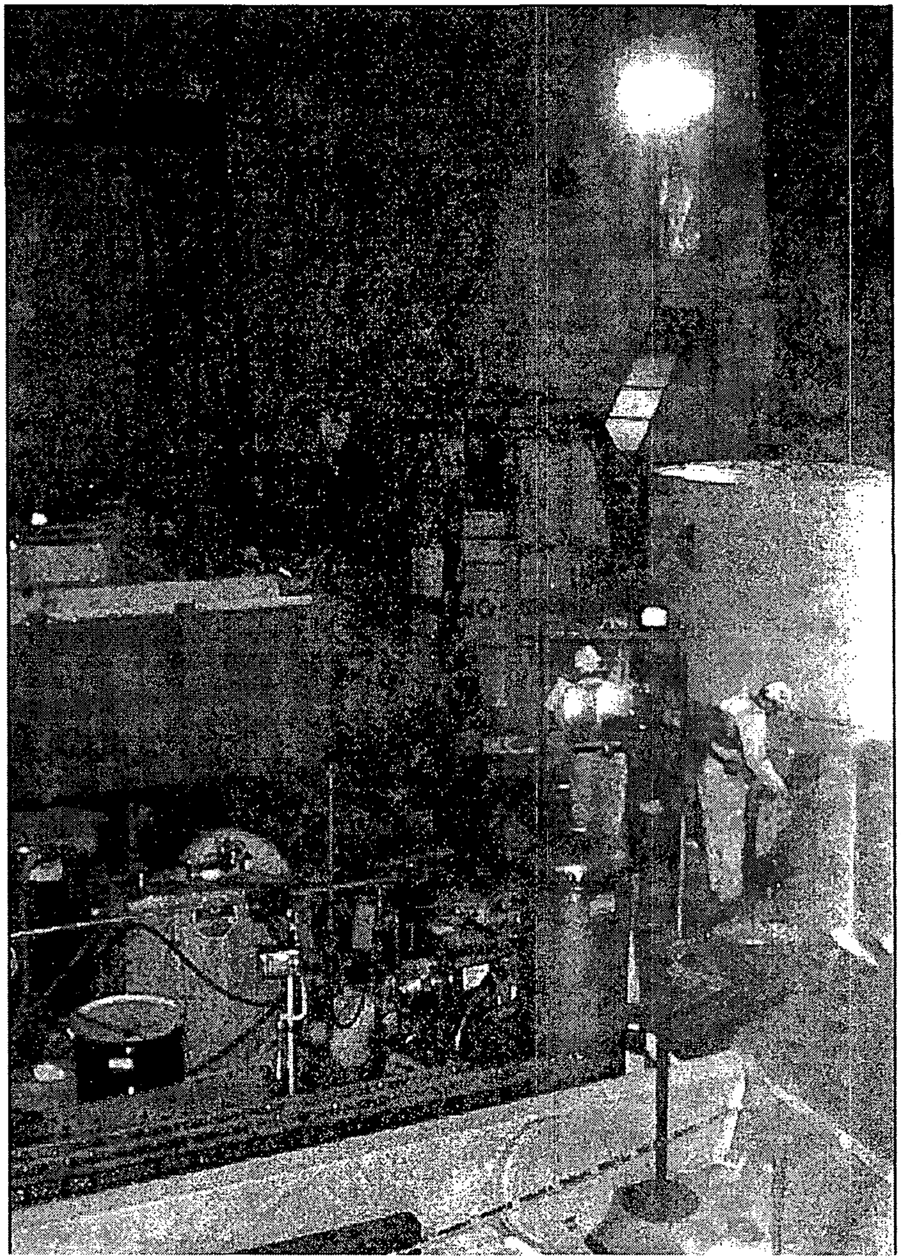
[2] The Department of Energy (DOE) is responsible for disposing of the spent fuel from commercial nuclear power plants in a geologic repository. Pending the approval and completion of the proposed Yucca Mountain repository project, owners of nuclear plants are storing their spent fuel at plant sites. NRC does not consider spent fuel storage and disposal costs as decommissioning costs.

Decommissioning Regulations Outline Technical Procedures

Before obtaining a license to operate a nuclear power plant, the licensee must agree with NRC to decommission the plant after the plant has been permanently shut down. NRC established its decommissioning requirements in regulations issued in 1988. Under these regulations, NRC expected that decommissioned sites, with rare exceptions, would reduce levels of radiation to allow the plant site to be released for unrestricted use once the license was terminated. Licensees had two decommissioning alternatives.[3] They could either begin major site decontamination and dismantling activities shortly after the termination of operations or maintain the plant and site in a safe condition up to several decades before dismantling the plant. Delaying full-scale decontamination and dismantling activities could be advantageous if (1) more time was needed to accrue decommissioning funds by continuing to collect funds from ratepayers after the plant has closed; (2) other units operating at the site would be disrupted unless all were decommissioned simultaneously at a future time; (3) a reduction in waste disposal volume, cost, or radiation exposure was possible because of a reduction in residual radiation over time; or (4) a licensed disposal facility for radioactive waste was unavailable. (Figure 1 shows ongoing decontamination and dismantling activities at one plant.)

[3] A third alternative—encasing radioactive wastes within the reactor building—was used by the DOE to decommission three of its small reactors. NRC, in promulgating its decommissioning regulations in 1988, opposed use of this decommissioning method for its licensees unless warranted to protect public health and safety. Since then, no licensee has proposed using this decommissioning method.

Figure 1: Ongoing Decommissioning Work Within the Containment Building at the Connecticut Yankee Atomic Power Company Haddam Neck Plant



Source: GAO.

When power operations at a nuclear power plant cease, the licensee must notify NRC, permanently remove the fuel from the reactor vessel, and confirm this action to NRC. Within 2 years, the licensee must provide a report to NRC addressing, among other things, decommissioning plans and the estimated costs of these activities. NRC then publishes a notice of receipt, makes the document available for public comment, and holds a public meeting in the vicinity of the plant to discuss decommissioning plans. The licensee may not perform any major decommissioning activities until 90 days after NRC receives the post-shutdown decommissioning activities report and the certifications of permanent cessation of operations and fuel removal. NRC currently requires that decommissioning be completed within 60 years unless public health and safety reasons require that an extension be granted.

Concurrent with plant decommissioning, a licensee must supply NRC a plan for terminating its license at least 2 years before the planned termination date. At the end of the license termination process, the licensee must conduct a final radiation survey to prove that the site meets radiological criteria for release and must include the survey with the plan. The licensee remains accountable to NRC until decommissioning has been completed and the license is terminated.

NRC's 1988 decommissioning regulations outlined several acceptable approaches for decommissioning nuclear power plants, but regulations did not establish acceptable residual radioactivity levels for the unrestricted release of decommissioned sites. In 1996, NRC published its final rule on the decommissioning of nuclear power plants. This final rule (1) redefined the decommissioning process; (2) defined terminology related to decommissioning; (3) required licensees to provide the NRC with early notification of planned decommissioning activities at their facilities; and (4) explicitly stated the applicability of certain NRC requirements that are specific for reactors that are permanently shut down. However, NRC did not amend its regulations to include radiological criteria for license termination until 1997. The final rule included radiological criteria for releasing decommissioned sites for both unrestricted and restricted future uses. For restricted future uses, licensees must provide safeguards to ensure that access to the site will be restricted until dose levels decay to the radiation level set for unrestricted site releases. The safeguards include requirements for physical barriers, security, monitoring, maintenance, financial assurance provisions, and other institutional controls to ensure that access to the site remains restricted for the entire internment period.

On the basis of its regulations restricting the dosages to members of the public under both the unrestricted and restricted release scenarios, NRC is also now considering two alternative decommissioning approaches. One approach, called rubblization, would permit licensees to demolish plant concrete that is contaminated with radioactivity into rubble and bury the rubble in the underground portion of the dismantled plant. The other approach, called entombment, would involve the permanent encasement of the radioactive contaminants from a partially dismantled plant within the remaining structure of the plant. NRC is also considering extending the timeframe for completing decommissioning from 60 to 100 years or more. As with other decommissioning alternatives, licensees selecting rubblization or entombment would be required to demonstrate compliance with NRC's regulations for license termination, including a demonstration that residual radiation doses at the site are as low as is reasonably achievable.

NRC has primary regulatory authority over nuclear power plant operations and decommissioning, but it is not the only entity that promulgates radiation protection standards. The Environmental Protection Agency (EPA) also issues radiation standards and administers the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA), which governs cleanups of federal and non-federal facilities. EPA has authority to evaluate NRC-regulated sites once the sites are decommissioned. NRC and EPA have historically disagreed over radiation protection standards. Differences in legislative mandates, agency missions, and regulatory strategies contribute to this disagreement, which remains essentially unchanged today despite resolution efforts spanning a number of years. States also have authority to issue their own standards, which may be more stringent than either NRC's or EPA's. Consequently, whereas NRC may approve decommissioning plans and terminate the NRC operating license based on its standards, plant owners may still be subject to other federal and state standards once the NRC license is terminated.

Decommissioning Regulations Outline Financial Procedures

NRC has authority under the Atomic Energy Act of 1954, as amended, to require licensees to accumulate the funds necessary to decommission their nuclear power plants. Prior to 1988, NRC only required licensees to certify that sufficient funding would be available to decommission their plants when needed and did not require any specific financial provisions. On July 26, 1988, NRC strengthened its technical and financial requirements for decommissioning and offered several options for providing financial assurance. The options included:

- prepayment of the entire estimated decommissioning liability in cash or liquid assets into a separate, segregated account outside the licensee's control;
- external sinking funds segregated from other licensee assets and outside licensee control that are established and maintained by periodic funding;
- surety methods or insurance; or
- for federal licensees only, a statement of intent that decommissioning funds will be obtained when necessary.

Essentially, most if not all utilities eventually elected the option to establish external sinking funds (trust funds) to finance future decommissioning costs. Under this option, decommissioning funds are accumulated over the operational life of a nuclear power plant as part of the cost charged to customers for the electricity they use.

In establishing its regulations, NRC recognized that the external sinking fund option allowed the rate-setting authority of FERC and state public utility commissions to control the rate at which decommissioning funds could be accumulated. Given the additional uncertainty involved in estimating future decommissioning costs, NRC required only that licensees provide "reasonable assurance" that sufficient funds would be available to decommission their nuclear power plants when they are shut down. In 1998 , NRC also began requiring licensees to provide financial reports every 2 years on the status of their decommissioning funds. NRC provided licensees with a mathematical formula to initially determine and periodically adjust the estimated amounts required in the funds for radiological decontamination of their plant sites. Licensees may also base their decommissioning trust funds on site-specific estimates of decommissioning costs if these estimates exceed the amounts calculated using NRC's formula.

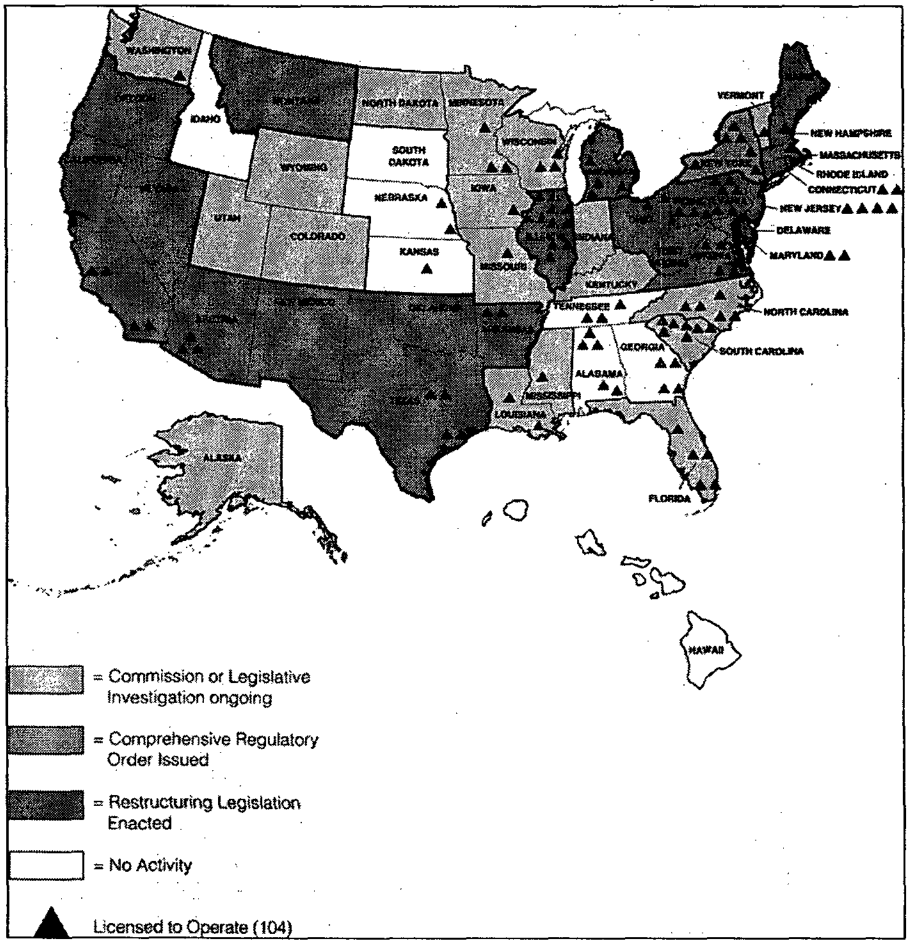
The length of time that a nuclear power plant remains in operation depends on several factors. NRC typically issues operating licenses for 40 years. Licensees with economically viable plants that still meet NRC's operational requirements may opt to extend operations rather than close their doors. On the other hand, licensees with financially marginal plants may decide to cease operations rather than shoulder large cost requirements for equipment upgrades or repairs, or to address NRC's concerns. An operational accident could also bring a premature end to operations, as could local public and political sentiment or NRC closure for safety reasons. As decommissioning funds are typically accumulated over the expected operational lifetime of the plant, plants that close prematurely may not have accumulated sufficient funds and may have to defer the decommissioning process. Furthermore, where several units are situated at the same site, licensees may delay decommissioning work until all plants can be decommissioned at the same time.

Deregulation of Electric Utilities and Resultant Industry Restructuring

Historically, nuclear power plants were constructed and operated primarily by investor-owned utilities.[4] Beginning in the mid-1990s, however, many states began to deregulate the electricity industry and to mandate or encourage industry restructuring. Under deregulation, subject to federal oversight, the ownership and control of electricity generation was separated from the transmission and distribution functions to facilitate competition. Traditional utilities continue to serve the transmission and distribution functions, while new business entities—formed through operating arrangements, plant sales, corporate realignments, and mergers—often handle the electricity production function. In recent years, NRC has reviewed more than 60 license transfer requests. These transfer requests have affected about half the nuclear plants in the United States, and some licenses were transferred several times for multiple reasons.

[4] In addition, smaller investor-owned utilities, publicly-owned utilities, or cooperatives own or have owned a few entire plants or shares of some plants.

Figure 2: Map of Nuclear Power Plants in the United States and Status of Deregulation by State



Note: Includes Browns Ferry Unit 1, which has no fuel loaded and requires Commission approval to restart.

Source: Nuclear Regulatory Commission and Energy Information Administration Illustrations, as modified by GAO.

While the move to deregulate the electric industry has resulted in changes that affect the status of licensees in some states, many licensees today still remain investor-owned utilities that operate as state-regulated monopolies. NRC has provided its staff, managers, and licensees with guidance on how it will review requests to transfer licenses, including determining whether the new license holders would continue to operate under economic regulation or in an economically deregulated environment. This guidance is in the form of a standard review plan on nuclear power plant licensees' financial qualifications to operate their plants and assurances that the licensees will provide adequate funds to decommission the plants. The review plan discusses each of the review procedures that the NRC staff should use, as appropriate, to determine the adequacy of a prospective licensee's financial qualifications and decommissioning funding method(s). For example, the review plan discusses how NRC's staff should evaluate external sinking fund trust documents and other decommissioning financial assurance mechanisms.

Objectives, Scope, and Methodology

Concerned about the adequacy of decommissioning funds, particularly in deregulated markets, Representative Edward Markey asked us to determine how (1) transfers of licenses to operate or own nuclear power plants affected the level of assurance that adequate funds will be available to operate and decommission these plants, (2) various site cleanup standards and proposed alternative decommissioning approaches affect projected decommissioning costs, and (3) proposed changes in financial reporting standards affect disclosure and funding of decommissioning liabilities.

To determine how license transfers for nuclear power plants affected NRC's level of assurance that adequate funds will be available to decommission these plants, we reviewed NRC's Standard Review Plan on Power Reactor Licensee Financial Qualifications and Decommissioning Funding Assurance, as well as related memoranda, regulations, policy statements, regulatory analyses, and regulatory guidance. We contacted NRC's Office of Inspector General to discuss the weaknesses it had reported in licensee's biennial reports to NRC regarding decommissioning fund balances. At NRC's headquarters in Rockville, Maryland, we met with officials from NRC's offices of Nuclear Reactor Regulation and Nuclear Material Safety and Safeguards to discuss decommissioning financial assurance issues regarding non-owner operating arrangements, nuclear plant sales, corporate reorganizations, and mergers. We also reviewed licensee information provided to NRC regarding these license transfers, and analyzed NRC's review and approval documents related to license transfer requests submitted for 9 non-owner operating arrangements, 19 sales, 3 corporate reorganizations, and one merger.

To determine how site cleanup standards and proposed alternative decommissioning approaches affect projected decommissioning costs, we obtained, from EPA and NRC, and reviewed memoranda, regulations and other documentation addressing decommissioning and radiation protection standards. We reviewed published GAO reports that dealt with decommissioning financial assurance, nuclear waste disposal, radiation protection standards, and other related issues. We also reviewed a recent National Research Council report that questioned the reliability of long-term institutional management controls at nuclear waste sites. We also contacted EPA and NRC staff regarding efforts to resolve interagency disagreement over radiation protection standards and related issues, and met with staff from NRC's offices of Nuclear Reactor Regulation and Nuclear Material Safety and Safeguards to discuss issues regarding radiation protection standards, past decommissioning methods and experience, and proposed decommissioning alternatives and their potential impact on decommissioning cost. In addition, we reviewed the minutes from an August 1999 NRC public workshop dealing with decommissioning and proposed waste disposal options.

To acquire a first-hand perspective on decommissioning, we obtained and reviewed the license termination plans from and made visits to the Connecticut Yankee Atomic Power Company plant at Haddam, Connecticut, and the Maine Yankee Atomic Power Company plant at Wiscasset, Maine. At the Haddam plant, we met and discussed decommissioning issues with officials from the Connecticut Yankee Atomic Power Company, Bechtel Power Corporation (the decommissioning contractor), and the Connecticut Department of Environmental Protection. We also toured the Haddam Plant and observed ongoing decommissioning work within the reactor building (containment). In addition, we met with local members of the Citizens Awareness Network, a non-profit volunteer organization, to discuss issues and concerns regarding the decommissioning of the Haddam Plant. In Maine, we met with two state senators knowledgeable about the controversy over original decommissioning plans to rubblize the Maine Yankee site and the involvement of the state legislature in the Maine Yankee decommissioning. We also met with a member of Friends of the Coast—a local citizens' environmental organization. We contacted officials from the Maine Department of Environmental Protection and Department of Human Services by telephone and discussed Maine Yankee decommissioning issues. In Washington, D.C., we met with members of the Nuclear Energy Institute, Union of Concerned Scientists, Nuclear Information and Resource Service, and Public Citizen to discuss decommissioning issues. In addition, we attended the Fifth Biennial Industry Conference on Decommissioning held in October 2000 and a NRC public decommissioning workshop held in November 2000.

To determine how a recently adopted financial reporting standard will affect the disclosure and funding of decommissioning liabilities, we reviewed the annual reports and/or annual filings with the Securities and Exchange Commission (Forms 10 K) for 55 utility companies that own nuclear power plants. From those, we determined the methods currently used to account for decommissioning costs. We also reviewed FASB Exposure Draft No. 206-B entitled "Accounting for Obligations Associated with the Retirement of Long-Lived Assets," (adopted in June 2001 as FASB Statement No. 143) as well as selected responses of public accounting firms and utility companies to the Exposure Draft. From our review, we determined how the new standard would affect the financial statements of utility companies with nuclear power plants.

We performed our review between June 2000 and August 2001 in accordance with generally accepted government auditing standards.

Chapter 2: Most Restructuring License Transfers Have Maintained or Enhanced Assurance of Decommissioning Funding

As a result of restructuring in the electricity industry, NRC has approved requests to transfer the licenses to own or operate more than one-half of the nuclear power plants in the United States. Some license transfer requests involved a single owner of one or more plants transferring licenses to own or operate the plant(s) to one or more new owners or operators. Other requests involved transfers of licenses to own or operate one or more plants from multiple owners of these plants. For most of the requests that NRC reviewed to transfer licenses for one or more plants, the level of assurance that the plants' decommissioning funds will be adequate has been maintained or enhanced. For example, when plant owners requested that their operating licenses for eight plants be transferred to a contractor, NRC maintained the existing level of assurance by continuing to hold the plant owners responsible for collecting decommissioning funds. In addition, when NRC approved requests to transfer licenses related to the sale of 15 plants, decommissioning funding assurances were increased because the selling utilities prepaid all or most of the projected decommissioning costs, and either the sellers or the new owners provided additional financial guarantees for those projected costs that were not prepaid. However, when NRC approved requests to transfer licenses in which the new licensee intended to rely on periodic deposits into external sinking funds for decommissioning, it did not always obtain the same level of financial assurance as when plants were sold or their operations contracted out. Among other things, NRC approved two requests to transfer ownership of 25 plants without verifying that the new owners would have guaranteed access to the decommissioning charges that their affiliated utilities would collect.

NRC also requires prospective new owners of plants that will not be selling their electricity at regulated rates to demonstrate their financial qualifications to safely own and operate the nuclear power plants that they are acquiring. In almost all of its reviews of new owners' financial qualifications, NRC has required additional guarantees from parent or affiliated companies that the new owners would have sufficient revenue to cover the plants' operating costs. However, when reviewing one prospective owner's financial qualifications, NRC did not require additional guarantees and did not validate the information submitted by the new owner to demonstrate that the company was financially qualified to safely own and operate the largest fleet of nuclear plants in the United States.

Funding Assurance Is Maintained for License Transfers Related to Contracting Out Operations

The level of assurance that decommissioning funds will be adequate has been maintained in all license transfer approvals that allowed plant owners to contract out plant operations. For example, traditional electric utilities that own 17 nuclear power plants have used companies that specialize in the operation, maintenance, and decommissioning of nuclear power plants to help them operate or decommission their plants. The owners of fifteen of these plants had to get NRC's approval to transfer their operating licenses. For the other two plants, NRC decided that the proposed arrangements did not require transfers of operating licenses. (See table 1.) For all 15 operating license transfers, NRC continues to hold the owners responsible for accumulating decommissioning funds, and the owners continue to collect these funds through regulated electricity rates. Accordingly, these operating license transfers have not changed the level of decommissioning funding assurance for these plants.

Table 1: Nuclear Power Plants With Non-owner Operating Arrangements

Nuclear power plant	Operator's business arrangement with owner(s)	NRC operating license transfer required?
Duane Arnold Energy Center	Operating services agreement[a]	Yes
Kewaunee Nuclear Power Plant	Operating services agreement[a]	Yes
Monticello Nuclear Generating Plant	Operating services agreement[a]	Yes
Palisades Plant	Operating services agreement[a]	Yes
Point Beach Nuclear Plant, Unit 1	Operating services agreement[a]	Yes
Point Beach Nuclear Plant, Unit 2	Operating services agreement[a]	Yes
Prairie Island Nuclear Generating Plant, Unit 1	Operating services agreement[a]	Yes
Prairie Island Nuclear Generating Plant, Unit 2	Operating services agreement[a]	Yes
John M. Farley, Unit 1	Affiliated company[b]	Yes
John M. Farley, Unit 2	Affiliated company[b]	Yes
Edwin I Hatch, Unit 1	Affiliated company[b]	Yes
Edwin I Hatch, Unit 2	Affiliated company[b]	Yes
River Bend, Unit 1	Affiliated company[b]	Yes
Vogtle, Unit 1	Affiliated company[b]	Yes
Vogtle, Unit 2	Affiliated company[b]	Yes
Clinton Power Station	Management services agreement[c]	No
Maine Yankee Atomic Power Plant	Management services agreement[c]	No

[a]Operating licenses for eight plants were transferred to one company, Nuclear Management Company, which was formed by the plants' electric utility owners to provide operating and eventual decommissioning services for the plants. NRC approved the operating license transfers but continues to hold the utility-owners responsible for collecting decommissioning funds for the plants through their regulated electricity rates.

[b]Seven transfers of operating licenses resulted from corporate reorganizations or mergers in which an existing operations organization split off from an electric utility and formed a new affiliated company specializing in nuclear plant operations. The utility owners continue to collect decommissioning funds for the plants through their regulated electricity rates.

[c]In two cases, in which utility owners entered into management services agreements with outside companies to assist them with operating and decommissioning their plants, NRC did not require operating license transfers. In both cases, NRC determined that because the management services provided by the operating companies did not involve activities that would require a license, such as maintenance of safety-related equipment or the emergency preparedness program, and because the utility owners retained final decision-making authority, no transfer of operating authority had taken place that required NRC's approval. The utility owners continued to collect decommissioning funds through their regulated electricity rates.

Source: GAO's analysis of NRC data.

Prepayment and Company Guarantee Methods Have Enhanced Funding Assurances When Licenses Are Transferred

When NRC has approved license transfers for plants that chose the prepayment and guarantee methods, assurance of adequate decommissioning funding has been enhanced. To date, all the transfers that NRC has reviewed as a result of plant sales have chosen either total prepayment or a combination of these methods. For example, as a direct response to deregulation legislation in many Northeast, Mid-Atlantic, and Midwest states, NRC has approved the transfer of the ownership interests in 15 nuclear power plants from traditional electric utilities to newly formed generating companies. The utilities selling 13 of these plants proposed to transfer prepaid decommissioning trust funds to the generating companies. NRC concurred with these proposals and also imposed conditions on how the new owners must manage these funds to ensure that they are preserved and accumulate as projected in a market environment. For the other two plants, the selling utility—the Power Authority of the State of New York—chose to retain control of the prepaid decommissioning trust funds for its two plants and not transfer them to the new owners (Entergy Nuclear Indian Point 3 and Entergy Nuclear Fitzpatrick). Because the Power Authority would no longer be a licensed owner or operator of the two plants, NRC imposed additional conditions upon these license transfers, allowing NRC intercession to release funds for decommissioning if the Power Authority does not comply with its responsibility to do so.

In three transfers the accumulated trust funds did not cover small portions—less than 8 percent—of the projected decommissioning costs. In these cases, either the buyer's or the seller's parent or affiliated companies passed NRC's financial test and provided contractual guarantees that they would provide additional funds as needed. Consequently, NRC has assurances that all approved new plant owners will have adequate funds available to decommission their plants in a deregulated environment. Table 2 lists the 15 plant sales that NRC has approved, along with the projected amount of decommissioning funding needed and the amount available in the trust funds at the time of the sales.

Table 2: Decommissioning Funds Needed, Transferred, and Assurance Methods Used for Nuclear Power Plants Approved for Sale

Dollars in millions

Nuclear power plant	Percent sold	Projected funds needed	Funds approved to transfer	Decommissioning assurance method
Clinton Power Station	100.00	$347.880	$210.000	Prepayment + 2% interest[a]
James A Fitzpatrick	100.00	$358.000	$343.968[b]	Prepayment + 2% interest[a] + guarantee
Hope Creek	5.00	$18.014	$9.681	Prepayment + 2% interest[a]
Indian Point, Unit 3	100.00	$292.000	$315.225[b]	Prepayment + guarantee
Millstone, Unit 1[c]	100.00	$504.481	$293.712	Prepayment + guarantee + 2% interest[a]
Millstone, Unit 2	100.00	$298.630	$252.944	Prepayment + 2% interest[a]
Millstone, Unit 3	93.47	$316.728	$246.838	Prepayment + 2% interest[a]
Oyster Creek	100.00	$333.462	$400.000	Prepayment
Peach Bottom, Unit 2	15.02	$56.401	$44.775[d]	Prepayment + 2% interest[a] + guarantee
Peach Bottom, Unit 3	15.02	$56.401	$46.202[d]	Prepayment + 2% interest[a] + guarantee
Pilgrim	100.00	$327.000[e]	$396.000	Prepayment
Salem, Unit 1	14.82	$44.000	$36.837	Prepayment + 2% interest[a]
Salem, Unit 2	14.82	$44.000	$35.635	Prepayment + 2% interest[a]
Three Mile Island, Unit 1	100.00	$268.870	$303.000	Prepayment
Vermont Yankee	100.00	$328.300[f]	$280.000[f]	Prepayment + 2% interest[a]

[a]NRC requirements in 10 CFR 50.75(E)(1)(i) and (ii) for the prepayment and external sinking fund assurance methods, respectively, allow licensees to take credit for future earnings on their trust funds at a real rate of return (i.e., adjusted for inflation) of up to 2 percent per year. Licensees may claim higher rates if specifically authorized by their rate regulator.

[b]The seller does not plan to transfer these funds to the new owner and will instead retain the trusts after the plants are sold. The seller has provided a guarantee that the funds will remain available for decommissioning. In addition, the seller has agreed, as a condition of the trust agreements that, since it will no longer be licensed, NRC may intercede to release the funds, if needed.

[c]This plant, permanently shut down in July 1998, has been defueled and placed in a "Cold and Dark" state by the seller. These funds are based on a site-specific estimate and include the buyer's parent company guarantee of $25,423,666. The funds are intended to support annual monitoring costs of $2,947,285 during SAFSTOR and to accumulate until 2054, when final decommissioning is anticipated.

[d]These funds are the cumulative funds collected by 2 utilities with equal selling shares; however, one utility has collected less than half of this amount. Originally both utilities, as subsidiaries of a single holding company, were to complete their sales at the same time and their combined funds were sufficient for prepayment assurance. However, the utility with the larger accumulation of funds delayed its transfer awaiting approval from its state public utility commission. Because the utility with less accumulated funds consummated its sale first, the other affiliated utility has guaranteed to make up the difference up to 50 percent of their cumulative amount until it completes its divestiture.

[e]This amount is the NRC generic formula estimate. A site-specific site cost estimate placed costs between $396 million and $466 million. The seller agreed to transfer $396 million to the buyer's decommissioning trust account and to create a provisional trust account of $70 million to cover the potential taxes that might be due. Any funds left in the provisional trust account after taxes, as of December 31, 2002, will be deposited in the decommissioning trust account.

[f]These are the amounts NRC approved in 2000; however in January 2001, the Vermont Public Service Board nullified this sale and, in the hope of receiving a better offer, ordered that the plant be sold at auction. These amounts will most likely change when the sale is consummated.

Source: GAO's analysis of NRC data.

Funding Assurance Was Not Always Maintained in License Transfers That Continued to Rely on the External Sinking Fund Method

In approving license transfer requests that continued to rely on the external sinking fund method of decommissioning financial assurance, NRC's reviews did not consistently maintain the level of assurance that decommissioning funds would be adequate, as it had for license transfers that relied on prepayment or company guarantees. In most cases, the new owners, as a result of corporate reorganizations or mergers, are no longer considered traditional electric utilities that will collect decommissioning funds through predetermined rates, but instead are affiliated with electric utilities authorized by their state regulators to collect non-bypassable charges for decommissioning.[1] These affiliated utilities will not be licensed by NRC. While NRC's review plan does not explicitly describe procedures for its staff to follow in these situations, it does imply that the new owners should provide NRC with additional information regarding the calculation and collection of these charges and ways they will be deposited into their trust funds. NRC, however, did not consistently request this additional information, when owners did not provide it. Consequently, NRC was unable to consistently maintain assurance that these funds would accumulate adequately when new owners rely on the traditional external sinking fund assurance method in a deregulated environment.

NRC Did Not Always Verify That New Plant Owners Would Have Access to Collected Decommissioning Charges

Our review of NRC's approval of license transfers for 28 plants from 3 corporate reorganizations and one merger revealed that the new plant owners had varying degrees of access to the future decommissioning charges collected for their plants. Even though NRC's regulations allow non-bypassable charges as an acceptable accumulation mechanism for external sinking funds, it assumes that NRC licensees will either collect these charges or have direct access to them. NRC did not consistently assure that when unlicensed affiliated utilities collect the charges, they would deposit them into the new owners' decommissioning trust funds.

For 3 of the 28 plants—units 1, 2, and 3 of the Palo Verde nuclear power facility in Arizona—NRC placed conditions on its approval of the license

[1] Non-bypassable charges are charges imposed over an established period of time by a government authority (such as a public utility commission) that affected entities are required to pay to cover the costs associated with the decommissioning of a nuclear power plant. Such charges include, but are not limited to, wire charges, stranded cost charges, transition charges, exit fees, or other similar charges.

transfers that contractual arrangements for collection and deposit of earmarked funds into the new licensees' decommissioning trust funds be completed. The three units are jointly owned by several traditional electric utilities, including the Public Service Company of New Mexico and El Paso Electric Company of Texas. These two companies are reorganizing their corporate structures to comply with new requirements to supply energy in New Mexico under deregulation. In accordance with these deregulation efforts, the two companies requested that NRC transfer their respective ownership licenses in the Palo Verde plants to new generating companies formed out of their corporate reorganizations—Manzano Energy Corporation in New Mexico and MiraSol Generating Company in Texas. In effect, these new generating companies also will inherit the external sinking funds intended to cover their respective shares of responsibility to eventually decommission the Palo Verde units. However, these external sinking funds were not sufficient to qualify as prepayment of estimated decommissioning costs. Therefore, each company provided NRC with copies of contractual agreements requiring their affiliated utilities to:

- collect decommissioning funds through their charges for distributing electricity in their service areas (also known as non-bypassable wires charges) imposed by their respective state public utility commissions or other regulatory entities, and
- deposit the collected money into the new generating companies' decommissioning trust funds periodically.

NRC approved the license transfers subject to obtaining final copies of the agreements between the affiliated utilities and the new generating companies and schedules showing how the decommissioning charges approved by the New Mexico and Texas state public utility commissions would fund the total decommissioning costs.[2] In both cases, NRC assured that the decommissioning charges collected by their affiliated utilities would be deposited into the new companies' external sinking funds and that the states' public utility commissions were assuring that the charges collected would be sufficient to cover the total decommissioning costs.

However, NRC approved applications to transfer the licenses for the other 25 plants without verifying that the new owners would have the same degree of access to the decommissioning charges or that the states' public

[2] The New Mexico legislature has extended the implementation of deregulation in its state for 5 years, and as a result, these corporate reorganizations have been postponed.

utility commissions would ensure the collection of the total decommissioning costs. For example, the Public Service Electric and Gas Company's (PSEG) corporate reorganization involved decommissioning trust funds for 5 plants. The New Jersey Board of Public Utilities authorized PSEG to continue collecting decommissioning funds through its distribution rates, yet NRC approved the trust funds to be transferred to PSEG Nuclear, the newly-formed generating company. NRC did not question the access PSEG Nuclear had to the funds collected by PSEG, its affiliate utility. In addition, NRC did not require a copy of a contractual agreement between the affiliates that guaranteed periodic deposits to the new owner's decommissioning trust funds as it did for Manzano Energy and MiraSol Generating Company. In support of its approval for these transfers, NRC staff told us that they also used publicly available sources of information, such as state restructuring laws or public utility commission web sites, when new owners did not provide information with their applications. Unfortunately, the staff did not document the content or use of such information in the records of these license transfer approvals so we could not verify the adequacy of NRC's review. Also, in the case of the five plants, the New Jersey restructuring legislation had authorized these charges. After 4 years, the Board of Public Utilities planned annual reevaluations to determine whether the decommissioning funds were overfunded or underfunded and then to authorize further charges accordingly. NRC's records do not show that its staff evaluated how New Jersey's proposed charges would affect the accumulation of the total costs needed to decommission each individual plant, despite guidance in its review plan and previous instances when the prepayment and company guarantee methods had been used. Yet, NRC approved the transfers after assuring itself that, in the aggregate, the 5 plants would achieve the full funding of their required decommissioning costs by the time they cease operations.

More significantly, in the merger of two companies that involved 20 nuclear plants in Illinois, New Jersey and Pennsylvania, the existing and new companies involved in the merger did not provide, nor did NRC request, copies of contractual agreements documenting that monies to be collected from utility customers in the states would be deposited in the respective decommissioning trust funds for each of the 20 plants. In this restructuring transaction, Unicom (the parent company of the electric utility known as Commonwealth Edison Company) and PECO Energy Company merged to form a parent entity—Exelon Corporation—and several wholly-owned subsidiary companies, including Exelon Generation Company, Commonwealth Edison, and PECO. The generating subsidiary company became the legal owner of Exelon Corporation's electricity generating assets. These assets included Commonwealth Edison's 10 operating nuclear power plants and 3 retired nuclear plants that have not yet been decommissioned. In addition, the assets included six operating and one retired nuclear power plant owned by PECO. The latter two subsidiary companies transmitted and distributed the electricity supplied by the generating subsidiary to electricity customers. As a part of this electricity restructuring, both Commonwealth Edison and PECO retained their responsibilities to collect charges from their customers for the future decommissioning of the 20 nuclear power plants now owned by Exelon Generation Company.

When Commonwealth Edison and PECO requested that NRC approve their proposed merger, the two utilities submitted similar, if not identical, statements that they would continue to collect decommissioning funds for their 20 nuclear power plants through their electricity distribution rates. The utilities added that they would also, as a matter of contract, transfer the funds collected to Exelon Generation Company—which would hold the operating licenses for the 20 plants—for deposit in each plant's respective decommissioning trust fund. However, unlike the license transfer cases involving the restructuring of Public Service Company of New Mexico and El Paso Electric, discussed above, Commonwealth Edison and PECO did not enclose copies of any intercompany agreements or rulings from their respective public utility commissions documenting these fund transfer arrangements. Furthermore, NRC neither requested either of the two utilities to submit such documentation nor, in the orders transferring the licenses for the 20 plants, did the NRC place any conditions that guaranteed that the utilities would collect and deposit decommissioning funds into the plants' trust funds held by Exelon Generation Company. Nevertheless, NRC's documents approving the Exelon merger state that Commonwealth Edison and PECO will collect the decommissioning costs through their distribution rates and then, as a matter of contract, pay these amounts to their affiliate, Exelon Generation Company, for deposit in the trust funds for each plant.

NRC's staff told us that they did not request documentation regarding Exelon Generation Company's access to the collected charges because this issue was covered by the deregulation legislation enacted in Illinois and Pennsylvania, copies of which they had obtained from publicly available sources. Conversely, because the implementation of the deregulation legislation in New Mexico and Texas had been delayed, the NRC staff needed to be sure that it received final copies of any agreements in the Palo Verde plants' transfers in order to assess their viability against any new legislative changes. However, neither Illinois' nor Pennsylvania's deregulation legislation refers to an unregulated newly-formed company's access to the charges collected by regulated affiliated utilities. We did locate an inter-company agreement attached to Commonwealth Edison's public-utility commission submission for approval of the merger, providing evidence that such an agreement exists and that the Illinois public utility commission is overseeing this access issue. However, NRC had no record of this agreement or the Commonwealth Edison and PECO submissions to their respective state public utility commissions. Also, while NRC staff told us that they accepted the companies' application as sworn statements that contractual arrangements existed, they did not document the basis for this opinion in their evaluation of the license transfer.

Accumulation of Decommissioning Funds for Retired Plants Is Also a Concern

Concerns have also surfaced over whether the collection of utility surcharges is sufficient to cover total decommissioning costs when plants are prematurely shut down. NRC's review plan provides procedures for verifying the accuracy of annual deposits to such funds when plants are operating. However, when plants are prematurely shutdown, the plan does not provide staff procedures to follow, leaving them instead to determine how to review the funds on a case-by-case basis. NRC's approval documents state that the decommissioning funding mechanism for all 20 of Exelon Generation Company's plants—16 operating and 4 retired—is the regulated charge collected by its distributing utility affiliates and that the collecting utility will make deposits into the decommissioning trust funds over the generating life of each plant. If the plants no longer generate electricity, it is not clear from the information the utilities submitted or NRC's review plan just how the funds would be collected, much less (as discussed above) how the deposits would be made to the trust accounts of the closed plants. NRC staff subsequently told us that their review of the Illinois and Pennsylvania restructuring laws showed that they allow for the collection of non-bypassable charges for plants that are shutdown and that their evaluation report was in error on this point. However, the staff evaluation of this publicly available information is not documented in NRC's license transfer records for this merger.

In addition, NRC did not apply the same review standards when it approved the transfers for these four retired plants as it did for another retired plant,[3] Millstone 1, which was recently sold along with its sister

[3] The four retired plants are Dresden, Unit 1 and Zion, Units 1 and 2 in Illinois and Peach Bottom, Unit 1 in Pennsylvania.

plants that are currently operating. Dominion Resources, Inc., the new owners' parent company, showed NRC the expected annual accumulation of funds, forecast an expected shortfall of $26 million resulting from additional annual monitoring costs incurred while the plant awaits the retirement of its sister plants, and provided a company guarantee for this expected shortfall. In contrast, neither Commonwealth Edison nor PECO provided more detailed information for the 4 retired plants than they did for the 16 operating plants. The application documents that Commonwealth Edison and PECO provided and NRC's approval documents make it difficult to discern

- which phase of dismantlement these 4 plants are in;
- how much, if any, of the trust funds has been spent so far shutting down the plants;
- whether Exelon Generation Company will incur unanticipated long-term stewardship expenses as a result of having to monitor these plants (as was the case of the Millstone retired plant); or
- which costs in the site specific estimates of these retired plants might impact Exelon Generation Company's ability to effectively decommission the facilities or safely operate their collocated plants.

NRC staff told us that their regulations do not require this level of detail to review the status of decommissioning funds for retired plants; however, they could not document that these plants had been evaluated on a case-by-case basis as their review plan recommends. Despite these ambiguities, NRC concluded that Exelon Generation Company had provided adequate assurance, even though it continued to rely on the external sinking funds transferred from Commonwealth Edison and PECO, that it would, in a deregulated environment, accumulate sufficient funds to decommission almost one-fifth of the nuclear plant fleet of the United States.

NRC's Reviews of New Owners' Financial Qualifications Have Been Complete, With One Significant Exception

Although NRC generally followed the guidance contained in its review plan when reviewing the financial qualifications of prospective licensees, it did not follow this guidance when it reviewed the financial qualifications of Exelon Generation Company to own and operate the 20 nuclear power plants formerly owned by Commonwealth Edison and PECO.

NRC requires prospective new owners of plants that do not qualify for "electric utility" status—licensees that will not be selling their electricity at regulated rates—to demonstrate that they are financially qualified to safely own and operate the nuclear power plants that they are acquiring. To review this aspect of proposed license transfers, NRC's review plan recommends that prospective new licensees demonstrate their financial qualifications to safely own and operate their nuclear power plants for the next 5-years by means of (1) contractual agreements with utilities that will purchase electric power from the licensee; (2) the sale of power from the licensee's non-nuclear generating capacity; (3) projections of market prices for the sale of power not covered by agreements; or (4) parent or affiliate company guarantees or lines of credit for contingency operating funds. NRC also compares a licensee's expected annual electricity production from its plants with past performance to determine the reasonableness of these projections. NRC uses this information to determine whether the prospective owners have demonstrated that they possess, or have reasonable assurance of obtaining, sufficient revenue to safely own and operate each plant.

For 19 sales, 2 reorganizations, and 1 merger—collectively involving transfers of licenses for almost 50 nuclear power plants—that we reviewed,[4] NRC found that the new licensees did not qualify for electric utility status.[5] Except for the merger, NRC received additional guarantees from parent or affiliated companies that the new owners would have sufficient revenue to cover the plants' operating costs. For example, the prospective new owners provided NRC additional assurance that they would produce enough revenue to cover the expected operating expenses of their plants through power purchase agreements, contingency funds, and lines of credit from affiliated or parent companies. In addition, one new generating company cited anticipated revenue from the sale of non-nuclear power that amounted to almost 75 percent of its total electricity production to supplement its ability to support its minority interest in 3 plants.

For each of the sales and reorganizations, the new owners provided some form of financial assurance for their ability to safely own and operate the plants they proposed to own in addition to the market sale of the electricity produced by the plants. NRC staff evaluated this information according to the guidance in its review plan. For the merger, however, the new owner did not submit and NRC did not request additional guarantees.

[4] The number of license transfers or transactions reviewed and plants affected are not equivalent. In many cases plant owners have reorganized, merged or sold their interests in the same plants and many plants have multiple owners.

[5] In one other reorganization, NRC found that the new licensee qualified as an electric utility.

In addition, NRC did not validate the information submitted by the new owner to demonstrate that the company was financially qualified to safely own and operate the largest fleet of nuclear plants in the United States.

When Unicom (Commonwealth Edison) and PECO merged into Exelon Corporation, the subsidiary Exelon Generation Company, which would hold the NRC operating licenses for the two companies' 16 operational and 4 retired nuclear power plants, did not meet NRC's definition of an electric utility. However, in their applications to NRC, Commonwealth Edison and PECO asked NRC to transfer their plants' licenses to Exelon Generation Company on essentially the same terms and conditions contained in their existing licenses—licenses which reflected that, as economically regulated utilities, Commonwealth Edison and PECO had guaranteed access to revenues to own and operate their nuclear plants. Commonwealth Edison and PECO addressed the issue of assurance that Exelon Generation Company would be financially qualified to own and operate their nuclear power plants by providing NRC with 5-year projections of expenses from the production and purchase of electricity and revenues from the market sale of this electric power. Among other things, this information included the estimated costs of:

- operating the new company's 16 operational nuclear power plants;[6]
- purchasing excess electric power from six nuclear power plants owned, or to be owned, by AmerGen Corporation. AmerGen, which was half-owned by PECO, was created to market electricity generated from power plants purchased and operated for that purpose. At that time, AmerGen owned three nuclear power plants and was attempting to purchase three other nuclear plants; and
- purchasing electricity from other suppliers for resale to Exelon customers, fuel costs, asset depreciation, and other administrative costs.

In addressing its potential revenue, Commonwealth Edison and PECO provided NRC with projections of revenues from, primarily, the sale of electricity produced by the 16 nuclear plants and the resale of the electricity purchased from AmerGen and other suppliers. Additional income, amounting to 6 percent of the total electric power to be sold, was

[6] Of these 16 plants, Commonwealth Edison and PECO owned majority interest and operated 14 plants. At two plants, Salem-Units 1 and 2, PECO owned a 42.59 percent interest and PSEG Nuclear operates the plants. Neither Commonwealth Edison nor PECO estimated annual electricity generation costs and revenue for individual plants.

derived from the market sale of 5,000 megawatts of power from non-nuclear plants.

Although Commonwealth Edison and PECO provided a financial projection to NRC in their license transfer applications, neither company provided, nor did NRC request, any additional support—power purchase agreements, contingency fund guarantees, or lines of credit—that would enable NRC to validate the Exelon Generation Company's financial qualifications to own and operate the largest fleet of nuclear plants in the United States. Also, Exelon did not provide, and NRC did not request, the 5-year projections of operating costs and estimated annual electricity generation for individual plants. For this reason, NRC could not, as its review plan recommends, compare plant-specific costs and production estimates to plants of similar size and type to confirm the reasonableness of the projections. Nonetheless, NRC concluded that Exelon's projected revenues, based solely on the market sale of electricity, would be sufficient to cover the costs associated with owning and operating 16 plants, even if it experienced simultaneous 6-month shutdowns of several of these nuclear plants.

Furthermore, NRC eventually transferred the licenses to Exelon Generation Company on the basis of projected financial information that both the affected companies and NRC knew to be inaccurate. When Commonwealth Edison and PECO updated their projected income statements for NRC in March 2000, they included income from three nuclear plants that AmerGen was attempting to purchase. However, there were no notes on this income statement to clarify that the statements included projected revenue from sales of electricity to be produced at nuclear plants that AmerGen did not yet own. (In contrast, Exelon Corporation did disclose this contingency in merger-related filings submitted to the Securities and Exchange Commission.) In June 2000, the merging utilities notified NRC that their March 2000 income statement was the most accurate. A month earlier, however, AmerGen had notified NRC that it had withdrawn its bid to purchase the two Nine Mile Point plants in New York. By December 2000 it was also apparent that AmerGen's bid to purchase the Vermont Yankee plant would not succeed. Therefore, AmerGen owned just 3 of the 6 plants Exelon Generation Company had included in its financial qualification statement. In January 2001—over 1 year after receiving the initial merger applications—NRC transferred Commonwealth Edison's and PECO's licenses to own and/or operate 20 nuclear power plants to Exelon Generation Company on the basis in part of projected financial information known to be inaccurate by the companies and NRC.

In defense of their review of the merger, NRC staff told us that their regulations only require that licensees demonstrate financial assurance through credible projections of 5 years of expenses and revenues. Also, because Exelon Generation Company was to be the licensee for all 16 operating plants, there was no compelling need to require plant specific information. The NRC staff maintain that they did perform an analysis of the impact of AmerGen's lost bids for the Nine Mile Point and Vermont Yankee plants and determined that there was no material impact on Exelon Generation Company's financial qualifications. Unfortunately, NRC did not document this evaluation in its review file and did not update the financial projections in their evaluation report to accommodate this analysis.

Conclusions

NRC's inconsistent review and documentation of license transfer requests creates the appearance of different requirements for different owners or different types of transfers. Good business practices suggest that NRC follow one review process with all of its licensees. While its standard review plan offers a sound basis for obtaining consistency, NRC is clearly not consistently achieving the desired results. One modification that could help NRC's staff and management maintain consistency in their reviews of license transfers is the use of detailed checklists or step-by-step processes delineated more precisely within its standard review plan.

Recommendation for Executive Action

To ensure that the decommissioning assurance methods and financial qualifications of all new nuclear plant owners are consistently verified, validated, and documented, we recommend that the Chairman, NRC, revise the Commission's standard review plan and related management controls for reviewing license transfers to include a checklist or step-by-step process for its staff, its management, and prospective owners to follow.

Agency Comments and Our Response

We provided NRC with a draft of this report for its review and comment. (See app. I for NRC's comments.) NRC disagreed with our recommendation. According to NRC, revising its review plan will not greatly enhance the effectiveness of its license transfer reviews because many of these transfers have been complex and unique. We disagree. When NRC drafted its review plan, it had no experience in regulating licensees that generate electricity in competitive markets. Since then, NRC has processed over 60 requests to transfer licenses. Although the details of each transfer request may have been unique, the affected licensees have consistently used the same few basic methods permitted by NRC's regulations, such as prepayment and/or parent company guarantees, to provide NRC with assurance that decommissioning funding and financial qualifications are being met. However, NRC's reviews of these license transfer requests have been inconsistent. Therefore, revising the review plan to ensure, on the basis of NRC's experiences to date, that each decision to approve a license transfer is based on consistent supporting information could increase NRC's efficiency and effectiveness, thereby helping NRC to achieve one of its primary performance goals.[7]

NRC raised several issues regarding its reviews of the adequacy of decommissioning funding and the financial qualifications of new owners of plants. NRC said its reviews of the PSEG and Exelon license transfers were adequate and complete, led to the conclusion that there was reasonable assurance of decommissioning funding and, in the Exelon case, that the new owners were financially qualified. NRC acknowledged that it did not appropriately document some of these evaluations. However, NRC asserted that, by reviewing other, unspecified, sources of financial information and information on the appropriate state's non-bypassable charges requirements, it was able to obtain reasonable assurance of decommissioning funding and financial qualifications. We disagree, for reasons that go beyond the lack of review documentation. Specifically, NRC's staff could not, in response to our requests, identify the specific sources upon which they relied, but did not document, for other information. Furthermore, we independently reviewed the state laws on non-bypassable charges for decommissioning funding that NRC's staff had referred us to and found that, while these laws provided for utilities to collect these charges, the statutes were silent on the procedures for depositing the charges collected into the plants' decommissioning funds. These collection and transfer procedures were left to appropriate state public utility commissions and, in many cases, had not been determined

[7] NRC's four performance goals are to maintain safety, increase public confidence, reduce unnecessary regulatory burden, and enhance the effectiveness and efficiency of its activities and decisions.

when NRC conducted its license transfer reviews. Nevertheless, NRC did not require the prospective new plant owners to make binding commitments with affiliated utilities or other enforceable statements of assurance that the non-bypassable charges collected by these utilities from their electricity customers would be transferred to the appropriate decommissioning fund for the new owners' plants.

Chapter 3: Regulatory Policies Under Consideration May Affect Decommissioning Costs and Nuclear Waste Policies

Varying radiation cleanup standards, the possibility that NRC will approve alternative decommissioning methods, and incomplete historical plant contamination data confound a licensee's ability to estimate future decommissioning costs. Varying radiation cleanup standards create uncertainty because plants decommissioned to NRC's radiation cleanup standards may also have to meet more stringent EPA or state standards, thus increasing the costs of decommissioning. Alternative decommissioning methods under consideration for approval would add uncertainty because no reliable data exist on their overall costs; they could reduce short-term decommissioning costs but add considerably to long-term costs. Moreover, implementing these methods would raise significant technical and policy issues pertaining to the management and disposal of radioactive wastes. Furthermore, the lack of complete historical information regarding plant contamination can translate into an unexpected increase in site cleanup costs late in the decommissioning process.

Varying Cleanup Standards Create Cost Uncertainties

To terminate an operating license and to release a site for unrestricted use, an NRC licensee must decommission its plant so that the residual radiation remaining at the site after decommissioning has been reduced to levels that meet NRC's standard.[1] However, meeting NRC's radiation cleanup standard may not signal the end of the decommissioning costs, because either EPA or the host state could require additional cleanup activity to meet more stringent standards.

While NRC regulates the decommissioning of commercial nuclear facilities, EPA issues general standards for radiation protection and administers CERCLA, which governs the cleanup of contaminated facilities.[2] NRC and EPA have historically disagreed on how restrictive U.S. radiation protection standards should be, and in 1997, EPA's Administrator told NRC's Chairman that NRC's radiation cleanup standard should be tightened to 15 millirems per year. The Administrator also called for adding a separate standard limiting the concentration of radiation in

[1] Under regulations issued by NRC in 1997, decommissioned sites that are decontaminated to residual radiation levels of 25-millirems or less may be released for unrestricted future uses. Decommissioned sites with elevated residual radiation levels of up to 500-millirems may only be released for restricted use, with safeguards and institutional controls to prevent public exposure.

[2] NRC's regulatory authority derives from the Atomic Energy Act, while EPA's derives from Presidential Reorganization Plan No. 3 of 1970 and CERCLA.

groundwater to 4-millirems per year. [3] These limits would be consistent with EPA's standards for cleanup at Superfund sites. If NRC did not agree, the Administrator said, EPA would have to reconsider its policy of exempting the sites of facilities regulated by NRC from EPA's National Priorities List of Superfund sites. Such action could subject NRC-decommissioned and released sites to a second evaluation under EPA's Superfund standards. EPA could conduct these subsequent evaluations under its own authority or when asked to do so by other stakeholders. It has provided guidance to its regional offices on how to proceed in such instances. However, the agency believes that the vast majority of decommissioned nuclear power plants will meet Superfund protection standards and is not actively looking for NRC sites to evaluate. Nevertheless, failure to pass a Superfund evaluation could mean significant additional cleanup costs.

NRC, however, shows no sign of changing its standards. NRC disagrees with EPA's preferences and questions EPA's technical basis for proposing the extra groundwater protection. Differences in agency missions, legislative mandates, and regulatory strategies contribute to this disagreement, which, despite resolution efforts spanning a number of years, remains essentially unresolved.[4]

According to the NRC Chairman, the disagreement over acceptable radiation standards is eroding public confidence and is negatively affecting efforts to assure the public that decommissioning can be accomplished in a manner that protects public health, safety, and the environment. In fact, in part because of the uncertainty over the scientific basis supporting radiation protection standards and the dispute between EPA and NRC, several states have established, or are in the process of establishing, their own radiation protection standards. Because most of these proposed or

[3] EPA does not actually express radiation protection standards in millirems but uses a system of "slope factors" to assign risk limits to individual chemical and radioactive contaminant types alike. These limits equate to a risk threshold of 1 in 1,000,000 that an individual will develop cancer in a lifetime or, with regard to radiation, roughly to a 15-millirem–a-year all-pathway radiation dose limit and a separate four-millirem-a-year dose limit for groundwater.

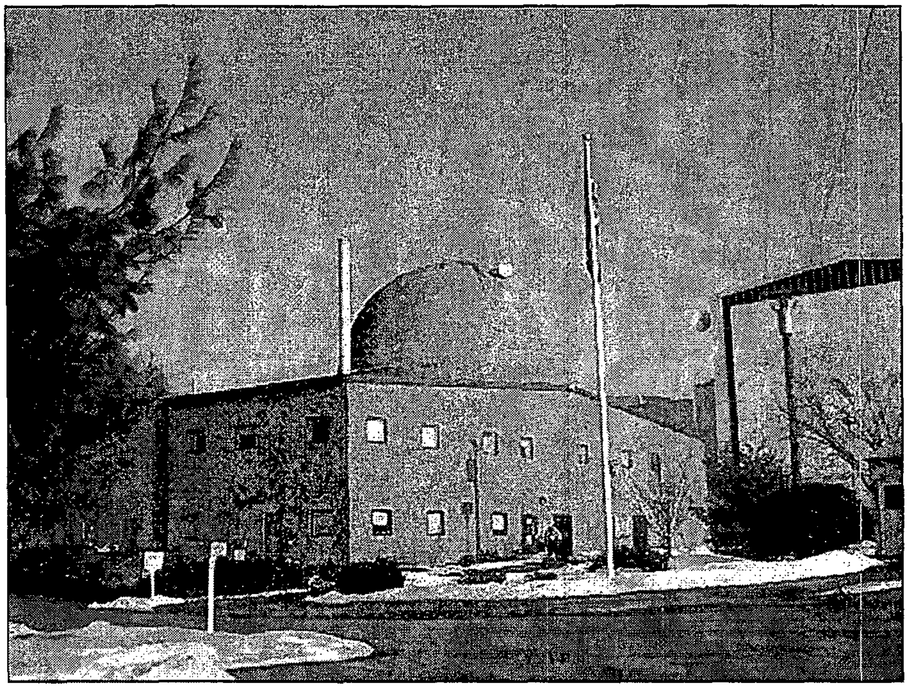
[4] *Radiation Standards: Scientific Basis Inconclusive, and EPA and NRC Disagreement Continues* (GAO/RCED-00-152, June 30, 2000); *Nuclear Regulation: Better Oversight Needed to Ensure Accumulation of Funds to Decommission Nuclear Power Plants* (GAO/RCED-99-75, May 3, 1999); and *Aging Nuclear Power Plants: Managing Plant Life and Decommissioning* (U.S. Congress, Office of Technology Assessment, OTA-E-575, Sept. 1993).

existing state standards are more stringent than either EPA's or NRC's standards, implementation of the states' standards could increase decommissioning costs.

For example, in April 2000, the state of Maine imposed a standard limiting the total effective annual dose from residual contamination at the Maine Yankee nuclear plant site to 10 millirems, with a separate 4-millirem dose standard for groundwater—which is below the dose allowed under either NRC's standard or EPA's preferred standard. Maine Yankee officials estimated that it would cost between $25 million and $30 million to ship and dispose of the waste materials that must be disposed of to meet the state's more restrictive standard.

Similarly, Massachusetts has set its own total effective annual dose equivalent standard of 10-millirem for decommissioned sites and New York has set a soil cleanup standard of 10-millirem for radioactive materials. New Jersey has set a 15-millirem residual radiation exposure standard, and the state of Connecticut is presently developing its own cleanup standards for commercial nuclear facilities. According to a state environmental department official, the new standard has not yet been officially approved, but will be the approximate equivalent of a 19-millirem dose limit, with a requirement to further reduce dose if it proves economically and environmentally feasible to do so. According to officials of the state and the Connecticut Yankee Power Company, the utility and the state are working together to ensure that the company will comply with the state's new standard, when issued, as well as NRC's and EPA's standards, in the decommissioning of the company's Haddam Neck nuclear power plant.

Figure 3: The Decommissioning Connecticut Yankee Haddam Neck Plant



Source: GAO.

Alternative Decommissioning Methods May Marginally Decrease Costs but Raise Significant Technical and Policy Issues

NRC is considering whether to authorize licensees to leave more radioactively-contaminated material at their plant sites when decommissioning nuclear power plants by either (1) reducing contaminated concrete to rubble and then burying the rubble on site or (2) removing the most radioactive plant wastes and entombing the residual radioactive materials inside the thick, reinforced concrete containment structure of retired plants. The rubblization and entombment methods could, if approved and implemented, decrease off-site waste disposal costs during the decommissioning of plants. However, short-term cost savings for some sites could be more than offset over the long-term because institutional control measures will be needed to prevent public access.

Short-Term Cost Savings Could Be Offset Over Time

According to the NRC Chairman, the low-level radioactive waste program in the United States is not working and the potential exists for the decommissioning process to be hampered at many sites unless alternative disposal options are pursued. States, the nuclear industry, and others have voiced similar concerns. Therefore, within the limits of its regulatory authority, NRC is considering decommissioning methods such as rubblization and entombment that would allow the permanent burial or encasement of radioactive waste at nuclear plant sites.

NRC believes that it is technically possible to approve a license termination plan that includes rubblization, as long as the total effective annual dose of radiation that a person living at the site would receive did not exceed the Commission's standards. Rubblization will be technically possible, NRC believes, as long as licensees are able to successfully address related issues, such as access to, and digging at, the sites where rubblization has occurred and the potential for reuse of extracted materials that are contaminated with radioactive elements.

Rubblization represents a departure from NRC's past licensing practice, which emphasized shipping low-level radioactive wastes from decommissioning sites to disposal facilities. Although NRC has estimated that rubblization could save a licensee from $10 million to $16 million in waste disposal costs during decommissioning, its Advisory Committee on Nuclear Waste has concluded that technical factors, such as the depth of radioactive contamination and the volume of rubblized waste, could significantly diminish the potential cost savings. The Advisory Committee also believes that evaluating radioactive material content and doses from rubblization, both at the site and in local groundwater, may prove difficult and expensive. The Committee has cautioned that estimates of cost savings from rubblization could be offset if extensive decontamination, sampling, and analyses are needed. Therefore, the Committee has recommended that NRC establish a test case for study to identify possible problems and solutions related to rubblization.

In April 1997, NRC's commissioners also requested NRC staff to revisit the entombment method of decommissioning, the use of which the commission had discouraged a decade earlier, to determine whether that method serves as a viable alternative to completely dismantling nuclear plants. The Commission added that, if the staff concluded that entombment is not a viable decommissioning method, the staff should describe the technical requirements and regulatory actions necessary for entombment to become viable, including the resources involved, potential decommissioning cost savings, and vulnerabilities.

NRC had considered entombment as a decommissioning method in 1988 but generally opposed its use because, among other things, (1) the method would require expenditures for maintenance, security, and other long-term institutional controls for at least 100 years that would about equal dismantlement costs and (2) regulatory changes occurring during the long entombment period might require additional costly decommissioning activity before entombed sites could be released for unrestricted use in the future. NRC determined that entombment would be acceptable only on a case-by-case basis when a licensee could demonstrate that (1) immediate or delayed dismantlement of its nuclear facility was infeasible, (2) radioactive decay would allow unrestricted release of a site in about 100 years, and (3) access to waste disposal facilities was not available. No licensee at any additional power reactors undergoing decommissioning has since proposed the entombment option.

On May 4, 1998, NRC's staff notified the Commission that, on the basis of its preliminary assessment of work performed for NRC by the Department of Energy's Pacific Northwest National Laboratory, consideration of entombment as a viable decommissioning method had merit. The Laboratory had estimated and compared decommissioning costs, radioactive waste disposal requirements, estimated radiation doses to persons, and institutional control requirements for the two decommissioning methods approved in 1988—immediate dismantlement and dismantlement after storage of 50 years or more—with two entombment variations. These entombment methods are immediate entombment of radioactive plant materials in the containment building and the storage of radioactive plant materials in the containment structure for over 100 years, followed by entombment.

Subsequently, on July 19, 1999, NRC's staff affirmed that entombment could be safe and viable, depending on specific site situations. NRC's staff said that entombment, when properly performed, should have little effect on health, safety, and the environment. In addition, the staff noted that the entombment of radioactive wastes within the containment building of a retired nuclear power plant could significantly reduce off-site waste disposal requirements and related costs—although cost reductions would be offset, to some degree, by the cost of maintaining and monitoring the entombed facility for 100 to 300 years.

The NRC staff's decision that entombment might reduce decommissioning costs is questionable. For instance, both plants that have already been decommissioned and plants in the process of decommissioning using the immediate decontamination and dismantlement option report higher costs than the figure used for this option in the Pacific Northwest National Laboratory analysis on which NRC's staff based its views. Furthermore, the minimum amounts required for this option (as determined by NRC's own generic formula) are significantly greater than the figure used in the laboratory's analysis. The laboratory's analysis also showed that neither immediate nor delayed entombment offer significant projected cost savings unless one assumed that entombment would lead to a reduction in long-term site security and insurance costs. Moreover, the laboratory's analysis showed that, even when reduced security and insurance costs are assumed, placing a retired plant in storage for approximately 50 years and then dismantling the plant is the least costly decommissioning method.

The laboratory also used a 130-year institutional control period in its analysis of the entombment method of decommissioning. NRC, however, has stated that if radioactive wastes entombed in a former nuclear plant include long-lived waste varieties, then the necessary period of institutional control could be extended to 300 years. In such a case, the cost for the additional 170 years of monitoring and surveillance needed could make both entombment options significantly more costly than the immediate dismantling of a plant and off-site disposal of its radioactive wastes.

Also, although the laboratory's analysis did not include entombment of Greater-Than-Class-C (GTCC) waste, NRC is considering the possibility of authorizing licensees to entomb GTCC waste rather than disposing of it in a geologic repository. Current regulations specify that GTCC waste is not generally acceptable for near-surface disposal without special processing and design and the case-by-case approval of NRC. GTCC waste from decommissioning a nuclear power plant is essentially comprised of radioactive internal reactor parts, which, while less radioactive than high-level waste such as spent fuel, remain radioactive for many thousands of years. However, including GTCC within the entombment structure would extend the required period of institutional control and its associated expense to thousands of years. Furthermore, regardless of the time period in which institutional controls would be required, a licensee would need to establish a funding mechanism to provide sufficient financial assurance that essential institutional controls would be carried out for the required time period. In contrast to immediately dismantling a plant and removing essentially all radioactive materials from the plant site, entombment would essentially make a former plant site a restricted storage or disposal facility for low-level radioactive waste for more than 100 years, which could hamper commercial reuse or resale of the site for the entombment period.

Finally, questions remain regarding the financial provisions for remediation in the event of a failure at an entombed site. According to NRC's staff, "very expensive remedies" could be required if an entombment configuration proved unable to adequately isolate radioactive contaminants over the 100-year or longer time period needed for radioactive decay. Given the length of time involved, states are concerned that they will have to pay remediation costs should an entombment fail.

Technical Issues Surround Alternative Decommissioning Methods

Aside from questionable cost benefits, rubblization and entombment raise a number of technical issues. For instance, NRC does not intend to require that sites where rubblized radioactive materials would be buried have protection equivalent to off-site disposal facilities for low-level radioactive waste. Disposal facilities for commercial low-level radioactive waste, which are licensed and regulated by NRC or by a state (under agreement with NRC), must be designed, constructed, and operated according to NRC's regulations (or compatible regulations issued by the host state). In addition, to obtain a license to build and operate a disposal facility, the prospective licensee must characterize the facility site and analyze how the facility will perform for thousands of years. However, according to NRC, a rubblized site is not comparable to a low-level radioactive waste disposal facility because

- the quantity, forms, and range of radioactive waste types buried at a nuclear plant site would be less,
- rubblization is a decommissioning action subject to the license termination rule rather than a radioactive waste disposal action subject to the licensing provisions of 10 CFR Part 61, and
- NRC's regulations for disposing of low-level radioactive waste apply only to facilities that dispose of waste from other sites and sources and not to sites where contaminated materials are to be rubblized and buried on-site.

Nevertheless, 10 CFR Part 61 does not differentiate between what does or does not qualify as a low-level waste disposal action or facility on the basis of the quantity, forms, or range of the low-level radioactive waste to be buried. Furthermore, NRC's view that rubblization does not constitute the creation of a low-level radioactive waste disposal site is not shared by EPA and at least three agreement states. When the Maine Yankee Power Company was considering rubblization as the decommissioning method for the Maine Yankee nuclear power plant, the state of Maine and EPA expressed concern that burying low-level radioactive waste at the plant site would be tantamount to creating an unlicensed low-level radioactive waste disposal facility. In fact, Maine's attorney general found that a strict application of Maine state law would have classified rubblization of the plant as such. Such classification would have, in turn, required state legislature and voter approval, licensing by NRC or the state, and eventual state ownership of the plant site. Furthermore, when NRC sent a draft entombment rulemaking plan, an Advance Notice of Proposed Rulemaking (ANPR), and the PNNL entombment assessment to agreement states for comment on March 7, 2001, two out of the three agreement states that commented responded negatively.

New York, for example, opposed any new rulemaking that would allow low-level or GTCC waste to be entombed at reactor sites in the state. The state also contended that such an action would be contrary to the intent of the Nuclear Waste Policy Act and would adversely impact the financial viability of existing or planned low-level radioactive waste disposal facilities and state compacts. The state pointed out that data presented in the PNNL assessment (as discussed above) indicated that long term storage followed by dismantlement was preferable to entombment.

The state of Illinois also found entombment to be problematic as a decommissioning method, urged that NRC prohibit that approach, and said it would resist its implementation. The state found entombment to be inconsistent with the waste management policy established by Congress through the Low-Level Radioactive Waste Policy Act as amended. Regarding NRC's position that entombment is a decommissioning rather than a disposal action, the state said:

"It is beneath the NRC to engage in the semantical charade of denominating long-term isolation of reactor waste as anything other than disposal. The Agreement States' authority to license disposal of LLRW at reactor sites includes authority over entombment of LLRW. Any attempt by the NRC to repeal Agreement State authority under the pretext of merely licensing the decommissioning of commercial nuclear power reactors is virtually guaranteed to be vehemently [opposed] by Agreement States. If it is the NRC's objective to assert permanent federal control and responsibility over reactor sites, using those sites as a multitude of sacrifice areas throughout the United States, IDNS submits that NRC should make its proposal to Congress for a full and vigorous national debate."

Water intrusion is also a major concern for rubblized or entombed sites, and the fact that most nuclear power plants are situated in shallow water table or flood plain locations may limit the viability of these options. Furthermore, should NRC decide to allow GTCC waste in an entombment, integrity of the concrete configuration would have to be assured for many thousands of years. However, experts cannot guarantee or predict the integrity of concrete after 500 years.

Other technical concerns about rubblization include the potential for buried concrete to leach from rubblized sites, adversely affecting local water quality; the propriety of diluting contaminated material by mixing the material with non-contaminated materials; and, how to demonstrate that the estimated radiation dose at a rubblized site has been reduced to a level "as low as reasonably achievable," as required by NRC.[5] As with any proposed decommissioning method, the licensee would have to address any relevant issues in the License Termination Plan, as well as demonstrate compliance with the License Termination Rule and requirements for the reduction of resulting residual radiation to levels that are as low as reasonably achievable. NRC is in the process of updating its generic environmental impact statement on radiological criteria for terminating nuclear facility licenses. The update will address, among other things, rubblization as a decommissioning method and may include issues such as the acceptability of mixing or diluting contaminated material, the environmental effects of leaving contaminated concrete at decommissioned sites, and the potential effects of widespread use of the rubblization method because of economic considerations. NRC intends to require an environmental review for each site that proposes rubblization. The new generic statement should be useful to NRC in reviewing the environmental effects of license termination plans based on rubblization.

NRC staff recognized in reaching their favorable conclusions on the viability of entombment in 1999, that statutory, regulatory, technical, and implementation issues, such as the appropriateness of relying on intruder barriers over a 1,000-year period, required further development. For example, the usefulness of the entombment decommissioning method could be limited by concerns over the reliability of long-term institutional controls. Such concerns are indirectly addressed in a recent National Academy of Sciences report on the long-term management of DOE's nuclear sites.[6] Many of the weaknesses addressed in the Academy's report may apply to the restricted release of NRC-licensed sites as well. For example, according to the Academy:

> The viability over time of land use restrictions is likely to be especially questionable in cases where contamination levels are not high enough to prohibit all public access but not

[5] NRC's "As-Low-As-Reasonably-Achievable (ALARA)" policy essentially requires licensees to reduce residual radiation at decommissioning below the level required for unrestricted release as long as it is economically and environmentally feasible to do so.

[6] *Long-Term Institutional Management of U.S. Department of Energy Legacy Waste Sites* (National Research Council, Committee on the Remediation of Buried and Tank Wastes, International Standard Book Number 0-309-07186-0, Copyright 2000, National Academy Press).

low enough to permit unrestricted use. Often the real issue is not **whether** use restrictions will eventually fail, but when and what the **consequences** will be when they do. [Emphasis in original.]

EPA has also questioned the reliability of long-term institutional controls, stating that among other things, long-term governmental controls may not be enforced effectively because of political and fiscal constraints on a state or local government's exercise of its police power.

NRC's Chairman has acknowledged that the need for long-term institutional controls is a significant weakness in decommissioning methods, such as entombment, in that states or other governmental agencies may not be willing to accept the responsibility for such controls. And, according to NRC's staff, the viability of entombment as a decommissioning method hinges, in part, on the Commission's decision on whether barriers to intrusion in the absence of institutional controls would effectively keep exposure to affected persons beneath the Commission's dose limits.

The reliability of institutional controls over entombments that include GTCC waste would be even more questionable because of the extremely long post-closure monitoring and surveillance timeframes that would be required. In fact, in its August 1988 generic environmental impact statement on decommissioning nuclear facilities, NRC's staff concluded that the entombment method with GTCC waste included in the encasement was not viable because the security of the site could not be assured for thousands of years. In 1998, NRC also said that analyses would be required to demonstrate that a proposed entombment was unlikely to fail over the proposed entombment period. Such a requirement would be difficult to meet if GTCC waste were stored in the entombment because, experts say, projections on the integrity of concrete after 500 years are speculative. Finally, NRC's staff has determined that the Low-Level Radioactive Waste Policy Amendments Act of 1985 and NRC's regulations essentially require that the disposal of GTCC waste be licensed and that GTCC waste be placed in a geologic repository.[7]

[7] During a NRC entombment workshop held in December 1999, DOE panel members stated that entombing GTCC waste in a reactor containment building is possible under existing legislation and that such an alternative was preferable to disposing of this type of waste in a geologic repository. The Low-Level Radioactive Waste Policy Act makes DOE responsible for disposing of commercially generated GTCC wastes.

Over the 100 to 300 year entombment period, early license termination and potential property ownership changes could also complicate the issue of financial responsibility for the entombment failure and subsequent responses. States are concerned that they may be obligated to pay the potential remediation costs if they have to assume oversight responsibility for an entombment after NRC has terminated a plant's operating license. For this reason, state representatives have said that, at least until experience with entombment has been acquired, NRC should continue to maintain some type of licensing responsibility at entombment sites. Such a step, however, would be contrary to NRC's goal of terminating licenses upon plant entombment.

Alternative Decommissioning Methods Potentially Conflict With National Policy

On-site burial of rubblized low-level radioactive waste or the entombment of these wastes on-site may conflict with national policy on management and disposal of these wastes. The Low-Level Radioactive Waste Policy Act of 1980, as amended in 1985, established as federal policy that commercial low-level radioactive waste—except for GTCC waste—can be most safely and effectively managed by states on a regional basis. Through the act, the Congress encouraged states to form regional compacts to meet their collective disposal needs, minimize the number of new disposal sites, and more equitably distribute the responsibility for the management of low-level radioactive wastes among the states.

To encourage the formation of such regional compacts, congressionally approved compacts are allowed to prohibit the disposal of wastes generated outside their respective regions. To date, 44 states have entered into 10 compacts. However, despite some 20 years of effort and the expenditure of about $600 million, no new regional disposal facilities have been provided as a result of the act, and no state or compact is currently trying to identify a site for a disposal facility. [8]

Commercial generators of low-level radioactive waste, including licensees that are, or soon will be, decommissioning their nuclear power plants, currently have access to off-site disposal facilities for this waste. Of the three currently operating disposal facilities for commercial low-level radioactive waste, the Barnwell, South Carolina facility is both available to

[8] For a fuller discussion of states' implementation of the Low-Level Radioactive Waste Policy Act, see *Low-Level Radioactive Wastes: States Are Not Developing Disposal Facilities* (GAO/RCED-99-238, Sept. 17, 1999).

generators in all states and licensed to accept all classes of waste for which states must provide disposal. However, whether such access will continue, and at what cost, is uncertain. Access to the Barnwell facility is to be phased out for most generators by mid-2008. Another facility—Envirocare of Utah—which is located west of Salt Lake City, Utah, is available to generators in all states outside the Northwest Interstate Compact region but is licensed to accept only the least radioactive class of such wastes. In July 2001, the operator of this facility obtained a license amendment from the state of Utah to dispose of the more radioactive classes of low-level radioactive waste. However, the facility must also obtain the approval of the state's governor and legislature for such disposal. The company has announced that, at this time, it will not pursue such approvals because of controversy over an unrelated proposal to develop a storage facility for spent fuel from commercial nuclear power plants.

Unless Envirocare obtains the required governmental approvals in Utah and expands its existing disposal facility, and absent any new initiative by a compact of states to develop other disposal capacity, by mid-2008 waste generators in 36 states, Puerto Rico and the District of Columbia, will have no access to a disposal facility for wastes that are not already approved for disposal at the Envirocare facility.

The potential lack of access to disposal facilities prompted NRC and the nuclear industry to explore the rubblization and entombment decommissioning methods. Concerns have been voiced, however, that rubblization and/or entombment could adversely affect disposal costs and/or the profitability and economic well-being of the existing disposal facilities, while making it economically infeasible for a compact to develop new disposal facilities. Thus, the two decommissioning methods appear to run counter to the existing national policy of encouraging states to manage disposal of low-level radioactive wastes on a regional basis.

Moreover, the rubblization and/or entombment decommissioning methods may also contravene some state-compact agreement provisions. As discussed earlier, for example, if rubblization of the Maine Yankee plant had occurred, the state could have determined that the rubblized site was a disposal facility for low-level radioactive waste. In such a case, according to Maine's attorney general, the state could have been in violation of the Texas Low-Level Radioactive Waste Disposal Compact, of which Maine is a member, because the compact terms make Texas—not Maine—responsible for developing the compact's disposal capacity for low-level radioactive waste generated within Maine, Texas, and Vermont.

Site Contamination Can Go Undetected Until Late in Cleanup Process

Site characterization is an essential step in the decommissioning process,[9] but NRC does not stipulate when site characterization must be done. The sole time constraint is that a site-characterization must accompany NRC licensee's license termination plan and that the license termination plan must be submitted to NRC at least 2 years before the requested termination date of the license. If site characterization work does not begin until the latter stages of decommissioning and survey work uncovers unexpected contamination, instances can occur where the balance remaining in the decommissioning trust fund may not be enough to cover the unplanned additional cleanup work required.

NRC requires licensees to document occurrences and locations of spills, leaks, and other events that may occur at the plant and result in site contamination. This documentation, combined with the institutional knowledge of plant employees, provides the basis for a plant's historical site assessment and characterization plans. Historical site assessment and characterization are essential to ensure and demonstrate that all impacted areas at the site have been identified and cleaned up to meet the appropriate dose level required for license termination.

In cases where nuclear power plants were operating before NRC imposed record keeping requirements for burials, spills, and so forth, or if required record-keeping was less than meticulous, the institutional knowledge of plant employees becomes an invaluable tool for disclosing incidents and locating where contamination might be present. However, once a plant announces its plans to decommission, employees are often let go or leave to take other jobs, diminishing the institutional knowledge. In situations where plants close and are placed in safe storage for a number of years before final decommissioning work begins, institutional knowledge may be all but lost. As a result, although surveys take place throughout the decommissioning process, some instances of contamination may not be discovered until comprehensive site characterization work begins.

For instance, one small nuclear plant—Saxton in Pennsylvania—was built on the site of an old steam generating plant. The nuclear reactor was purposely built on this site to utilize an existing turbine and associated equipment from the steam plant. The nuclear reactor was shut down in

[9] Site characterization entails radiological surveys of site grounds and facilities to insure that residual radiation at the site is in compliance with the appropriate NRC-prescribed dose limits for license termination and site release.

1972. In 1975 the steam plant was demolished and the basement was backfilled with demolition debris. The nuclear facility was maintained in a monitored condition, and full-scale decommissioning work did not begin until May 1998, 26 years after the plant was permanently shut down.

After initial site characterization and submission of the License Termination Plan in early 1999, unexpected additional contamination was discovered that required complete removal of all concrete in the containment structure and excavation, characterization, and remediation of the old steam plant basement. The estimated cost for this work exceeded the balance remaining in the decommissioning trust fund, forcing the owners to pay for it out of their general operating funds.

An NRC official told us that the plant owners are committed to doing a quality decommissioning job and that many of the problems found have been identified as a result of their diligence in approaching the decommissioning task. Nevertheless, historical site assessment efforts might have been easier to perform and more input from plant employees might have been obtained had initial site characterization work begun closer to plant shutdown and unexpected contamination problems been discovered sooner. Because the licensee was initially able to collect decommissioning costs from the ratepayers after the plant shut down, ratepayer contributions to the decommissioning fund might have been increased, or decontamination and dismantlement could have been delayed to allow for decommissioning fund investment income to grow to meet additional decommissioning costs before the principal was spent.

Conclusions

The actual cost incurred to decommission a nuclear power plant site is affected by many factors, some of which lie beyond a licensee's control. One of these factors is uncertainty over the application of radiation protection standards. Though NRC's licensees accumulate funds to decommission their plants to NRC's standard, once the time to decommission a plant arrives, a licensee may find that it must also meet a more stringent EPA or state standard at higher than anticipated cost. Another factor is whether, in the future, licensees will have access to affordable disposal capacity for the low-level radioactive waste generated in the decommissioning process. Licensees' and NRC's interest in rubblization and entombment, as alternative approaches for decommissioning, attempts to address this uncertainty, but in turn raises equally important technical and policy issues pertaining to on- and off-site disposal of low-level radioactive wastes and the proliferation of radioactive waste disposal sites around the country. Also, the potential short-term cost savings from these methods may be more than offset if safeguards and institutional controls are required to ensure the safety of rubblized or entombed sites over the longer term. And the principal advantage of rubblization and entombment appears to be the disposal of radioactive waste at nuclear plant sites, which may not comport with current federal policy encouraging states, by means of congressionally-approved compacts, to be responsible for this function. Leaving low-level radioactive wastes buried or entombed at nuclear plant sites would make it more difficult for the existing low-level radioactive waste disposal program to succeed economically, thereby undermining the objectives of the Low-Level Radioactive Waste Policy Act, as amended.

There is, however, a way to alleviate some cost uncertainty in the decommissioning process without major technical and policy ramifications. Licensees could conduct historical site assessments/characterization surveys soon after the decision is made to permanently cease operations. Such early characterization would minimize the chances of the discovery of contamination problems late in the decommissioning process, when most or all of the funds have been spent. It would also provide licensees more time to adjust the accumulation of decommissioning funds accordingly.

Recommendations for Executive Action

We recommend that the Chairman, NRC, in the Commission's ongoing consideration of modifications to radiological criteria for terminating licenses and alternative decommissioning approaches, address

- how the burial or entombment of low-level radioactive waste at nuclear plant sites, leading to a potentially large number of contaminated sites scattered around the country, affects the federal policy under the Low-Level Radioactive Waste Policy Act to manage radioactive waste on a regional basis; and
- concerns about whether these decommissioning approaches are technically compatible with provisions of the Low-Level Radioactive Waste Policy Act, the interstate compact agreements that implement the act, and NRC's technical regulations on licensing disposal facilities for low-level radioactive waste.

To reduce the likelihood that site contamination will go undetected until late in the cleanup process, we recommend that the Chairman, NRC, require licensees to survey their plant sites for radiation immediately following the announcement of intentions to permanently cease operations, rather than allowing them to wait until 2 years before decommissioning is supposed to be complete.

Agency Comments and Our Response

NRC stated that it intends to consider our recommendations, as they pertain to the entombment alternative, during its ongoing rulemaking proceeding on that option. NRC added that it will obtain input from stakeholders on addressing the technical and policy concerns associated with the entombment decommissioning approach.

NRC disagreed with our recommendations as they pertain to rubblization. The burial of radioactive rubble at the site of a former nuclear plant, NRC said, would be subject to its license termination rules and not its regulations governing the development and operation of facilities for disposing of low-level radioactive wastes. We, however, like EPA and the State of Maine, find it difficult to discern why radioactive material buried on-site—material that has traditionally been shipped to disposal facilities designed and regulated for such purpose–does not merit the same protection as material sent to a low-level waste disposal site.

NRC also disagreed with our recommendation to require earlier characterization of sites where plants are to be decommissioned because earlier characterization, in its view, will not add significant value to the decommissioning process. We disagree. There is always the chance that contamination exists at a plant site that has not been documented. Although there is no guarantee that early historical site assessment and characterization work would identify all such instances, the chances of doing so would be enhanced by the availability of plant employees knowledgeable about past plant operations and site conditions. Delaying this work until essentially the end of the decommissioning process—after many employees who are familiar with a plant's operational history are gone—decreases the available institutional knowledge. Such delay also limits the ability of the licensee to acquire more decommissioning funds if necessary to cover increased decontamination expenses.

Chapter 4: New Accounting Standard Improves Financial Reporting but Cannot Ensure Adequate Decommissioning Funding

Recent changes to financial reporting standards for asset retirement obligations, established by the Financial Accounting Standards Board in June 2001, will require owners of nuclear power plants, among other affected industries, to report estimated decommissioning costs as liabilities in their financial statements. When implemented, the new standard will improve consistency in plant owners' reporting of these costs, which previous accounting practices allowed to be reported in a variety of ways. However, as an accounting standard it cannot guarantee that licensees have the funds available for decommissioning.

The estimation of decommissioning costs for nuclear regulatory purposes is an uncertain process, influenced by such matters as applicable cleanup standards and the selection of a decommissioning method. Moreover, liability amounts that companies owning nuclear power plants disclose in their financial statements may differ from the amounts determined under NRC's regulatory requirements. The new accounting standard, for example, will require public utilities and electricity generating companies to measure the liability of decommissioning costs using the "fair value" method.[1] In contrast, NRC requires licensees to estimate the cost of decommissioning their plants using a generic formula that takes into account the electrical output of the plants and derives from technical analysis of previous decommissioning activities. Alternatively, NRC allows licensees to base decommissioning costs on site-specific cost estimates if these estimates exceed the amounts calculated under the minimum funding requirements prescribed by NRC.

Finally, the new accounting standard cannot ensure that funds will be available at the time of decommissioning. Accounting standards are concerned with how financial events and obligations are reported; they do not ensure that resources will be available to pay for future needs, including decommissioning costs.

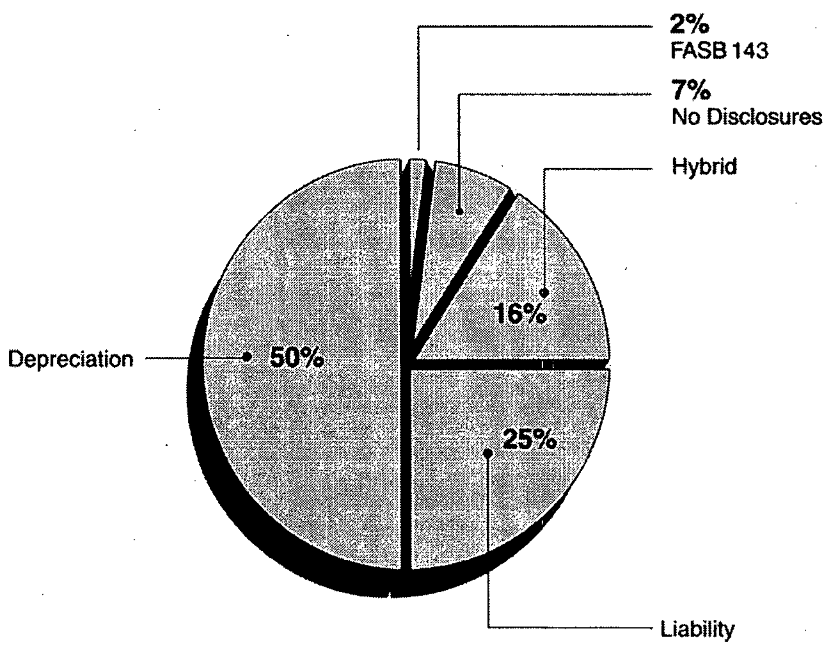
[1] Fair value is the amount that an entity would be required to pay in an active market to settle the asset retirement obligation in a current transaction in circumstances other than a forced or liquidation settlement.

New Accounting Standard Will Improve Consistency of Reporting

Utility companies have used a variety of methods to report estimated costs of decommissioning nuclear power plants. Implementation of the new standard in mid-2002 will improve consistency in plant owners' reporting of these costs.

On the basis of our review of the 1999 annual financial reports of 55 utility companies, we determined that about 75 percent of the companies have used one of two methods—the depreciation method or the liability method—to account for their decommissioning costs. The remaining companies used either a hybrid method (16 percent); or the method included in the new accounting standard (2 percent). (See fig. 4.) We were unable to determine the method used by 7 percent of the utility companies because of insufficient disclosures in the financial statements.

Figure 4: Methods Currently Used to Account for Decommissioning Costs



Source: GAO analysis.

Utility companies most frequently accounted for nuclear decommissioning costs as a component of depreciation expense. Using this method, an expense is reported each year for a portion of the amounts collected from customers in utility rates; however, instead of recording a liability, the reported amount for the plant asset is reduced by the amount of the expense. This method could ultimately result in a negative book value for the plant asset.

Using the liability method, an expense is reported each year for a portion of the amounts collected from customers in utility rates, with an equal amount added to a liability. The "bottom-line" (net income), as well as net assets, remains the same under both methods.

A comparison of the depreciation and liability methods to the new accounting standard shows that only the new standard requires the total estimated liability to be reported at plant startup, as well as a corresponding plant asset. (See table 3.)

Table 3: Comparison of Methods to Report Decommissioning Liability

Reporting approach	Depreciation method	Liability method	New standard
Full liability reported at inception	No	No	Yes
Liability gradually reported in an increasing amount	No	Yes	No
Plant asset cost amount includes the estimated decommissioning liability	No	No	Yes

Source: GAO analysis.

In February 2000, the Financial Accounting Standards Board (FASB) issued for comment an exposure draft entitled Accounting for Obligations Associated with the Retirement of Long-Lived Assets, which discussed nuclear plant decommissioning, among other types of asset retirement obligations. After obtaining and considering public comments, in June 2001 the Board unanimously voted to issue the standard in final form, effective for fiscal years beginning after June 15, 2002. Under this new standard (Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations), the fair value of the decommissioning costs is capitalized as part of the cost of the nuclear plant and an equal amount is recorded as a liability on the balance sheet.

In addition to requiring utility companies to recognize the full estimated cost of decommissioning at plant start-up, the new accounting standard also requires additional disclosures to investors, including:

- a general description of the plant retirement obligation (the liability);
- the fair value of assets, if any, dedicated to satisfy the liability; and
- an explanation of any significant changes in the liability.

New Accounting Standard Does Not Ensure Adequate Funding for Decommissioning Costs

The new accounting standard will not ensure that owners of nuclear power plants accumulate adequate funding for decommissioning costs. The Financial Accounting Standards Board is responsible for establishing standards of financial reporting, but not for ensuring that funding for liabilities reported under those standards will be available. The latter responsibility remains with NRC as a part of its regulation of nuclear power under the Atomic Energy Act of 1954, as amended, and other legislation.

Agency Comments

NRC stated that it neither supports nor opposes the new accounting standard. NRC added that the accounting standard and NRC's biennial financial reporting requirements were developed by distinct organizations for different purposes. Finally, NRC said it understands that the purpose of the Financial Accounting Standards Board's standard is to ensure the consistency of financial reporting. The standard is not, NRC added, meant to duplicate NRC's responsibility of assuring the availability of adequate decommissioning funds.

Appendix I: Comments From the Nuclear Regulatory Commission

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

November 2, 2001

Ms. Gary L. Jones, Director
Natural Resources and Environment
United States General Accounting Office
Washington, D.C. 20548

Dear Ms. Jones:

I am responding to your October 1, 2001 request that the U.S. Nuclear Regulatory Commission (NRC) provide comments on the draft General Accounting Office (GAO) report to the Honorable Edward J. Markey, House of Representatives, entitled "Nuclear Regulation - NRC's Assurances of Decommissioning Funding During Utility Restructuring Could be Improved."

The NRC provided the GAO with comments on the statement of facts associated with this report during an exit meeting with GAO staff on September 7, 2001. We are pleased that GAO incorporated many of the NRC's comments from the exit meeting in the October 1, 2001, draft report. GAO determined that most restructuring license transfers have maintained or enhanced assurance of decommissioning funding, and GAO also has provided constructive comments regarding documentation of the financial considerations associated with power reactor license transfer requests.

However, we continue to be concerned that GAO has not fully represented certain aspects of the NRC's license transfer review process, nor entirely considered the various processes associated with the decommissioning of a power reactor facility. The enclosed comments are intended to provide a more comprehensive perspective related to the conclusions and recommendations contained in GAO's draft report.

Sincerely,

William D. Travers
Executive Director for Operations

Enclosures: As stated

NRC COMMENTS ON DRAFT GENERAL ACCOUNTING OFFICE (GAO) REPORT TO THE HONORABLE EDWARD J. MARKEY, HOUSE OF REPRESENTATIVES, "NUCLEAR REGULATION - NRC'S ASSURANCES OF DECOMMISSIONING FUNDING DURING UTILITY RESTRUCTURING COULD BE IMPROVED"

1. GAO begins Chapter 2 of the draft report by stating (p. 20) that "for most of the requests that NRC reviewed to transfer licenses for one or more plants, the level of assurance that the plants' decommissioning funds will be adequate has been maintained or enhanced." However, GAO then cites two specific license transfer reviews that caused it concern, and GAO concludes Chapter 2 by stating (p. 33) that "NRC's inconsistent review and documentation of license transfer requests creates the appearance of different requirements for different owners or different types of transfers." Based on this conclusion, GAO recommends that NRC revise its standard review plan (NUREG-1577, Revision 1, "Standard Review Plan on Power Reactor Licensee Financial Qualifications and Decommissioning Funding Assurance," hereinafter referred to as the SRP) and related controls for reviewing license transfers to include a checklist for NRC staff to follow.

   NRC conducted two separate detailed financial reviews. The cited reviews concerned the corporate reorganization of Public Service Electric and Gas Company (PSEG) and the formation of Exelon Corporation (Exelon) through a merger between Unicom and PECO Energy Company.

   NRC believes that the actual decommissioning fund assurance (DFA) reviews associated with the PSEG and Exelon license transfers were adequate and that reasonable assurance of decommissioning funding was ascertained. In accordance

-1- Enclosure

NRC staff verified that adequate decommissioning funding would be maintained by reviewing other sources of financial information in addition to the application materials, including publicly available information concerning the appropriate State's non-bypassable charge requirements. In the PSEG review, NRC specifically documented a detailed and thorough evaluation of applicable State law pertaining to DFA, which, in conjunction with NRC license conditions required by the PSEG order, provides reasonable assurance of decommissioning funding for PSEG's plants. NRC staff also followed the SRP guidance regarding adequate review of applicable State legislation pertaining to DFA in the Exelon review to ensure conformance with applicable NRC regulations and to obtain reasonable assurance of decommissioning funding. NRC, however, agrees with GAO that the DFA aspect of the Exelon review was not appropriately documented.

With respect to financial qualifications reviews, GAO concludes (p. 30-31) that NRC's review of Exelon's financial qualifications for operating a large fleet of nuclear reactors was not complete and not conducted in accordance with the SRP guidance. Again, the NRC believes that this conclusion is a reflection of a lack of documentation, rather than any substantive deficiency in the actual review. NRC staff followed the SRP guidance by evaluating the appropriate information needed to obtain reasonable assurance of Exelon's financial qualifications to own and operate its reactors safely. NRC acknowledges, however, that some of the factors associated with the Exelon review were not appropriately documented, such as the NRC staff's finding that certain changes in financial projections would not have had a material effect on NRC's determination of Exelon's financial qualifications.

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Regarding GAO's recommendation for developing a license transfer review checklist (p. 33), NRC does not believe that a checklist will greatly enhance the effectiveness of license transfer reviews because many of the reviews that have been performed over the last few years have been very complex and, in many aspects, unique. GAO's assessments of the PSEG and Exelon reviews appear to be based largely on the lack of adequate documentation supporting the decision-making logic provided in the SRP. Therefore, NRC believes that appropriate documentation of the logic supporting each license transfer review will help to further demonstrate the adequacy and effectiveness of each review. The NRC will seek to ensure proper documentation is maintained to address GAO's concern of the appearance of different requirements.

2. In Chapter 3 of the draft report, GAO concludes (p. 50) that the proposed alternative approaches for decommissioning (i.e., entombment and rubblization) raise equally important policy and technical issues. GAO also recommends (p. 50) that NRC require site radiation surveys to be performed immediately after a licensee announces its intention to permanently cease operations to minimize the chances of the discovery of contamination problems late in the decommissioning process.

NRC agrees that the issues raised in the draft report are important. Although NRC has previously identified DECON and SAFSTOR as the preferred alternatives, NRC is evaluating whether ENTOMB, under certain circumstances, may be an allowable alternative. NRC intends, during the ongoing entombment rulemaking effort documented in SECY-01-0099, to consider GAO's recommendation and obtain stakeholder input for addressing the technical and policy concerns associated with the

3 Enclosure

entombment alternative approach. Regarding rubblization, NRC considers the rubblization process to be subject to the license termination rules of 10 CFR Parts 20, and 50, instead of the low-level waste requirements of 10 CFR Part 61 because the intent is not to create a low-level waste disposal site.

NRC believes that GAO's site survey recommendation would not add significant value to current decommissioning practices. Under current regulations, a licensee may begin substantial decommissioning activities, such as removing and dismantling various facility systems and structures, prior to site characterization. An immediate site characterization survey performed prior to these decommissioning activities, as recommended by GAO, would not necessarily identify all potential areas of radioactive contamination because there may be sources of radioactivity that cannot be identified or adequately assessed until many of the facility systems and structures are dismantled and removed. Therefore, GAO's recommendation may not necessarily be cost effective, because additional site characterization surveys may need to be performed in order to thoroughly understand the contamination remaining after the removal and dismantlement of facility systems and structures.

3. In Chapter 4, GAO (p. 53-54) states that the new accounting standard set forth in June 2001 by the Financial Accounting Standards Board (FASB) will improve the consistency of reporting estimated decommissioning costs in financial statements, but will not ensure that licensees will have adequate funds for decommissioning. The NRC neither supports nor opposes the new FASB standard. The NRC notes that, at one point, it intended to adopt the FASB standard for reporting decommissioning costs as a way to

4 Enclosure

obtain additional information on the status of decommissioning funds, but that the FASB standard was delayed for several years. In September 1999, the NRC promulgated additional reporting requirements for the status of decommissioning funding, obviating NRC's need for the new FASB standard. The new FASB standard and the NRC's decommissioning funding status reports were developed by two distinct organizations for different purposes. The NRC agrees with GAO's statement that NRC, not FASB, is responsible for ensuring that NRC licensees will have adequate funds for decommissioning, and understands that the purpose of the FASB standard is to ensure the consistency of financial reporting and is not meant to provide a means of assuring the availability of adequate decommissioning funds.

Appendix II: GAO Contact and Staff Acknowledgments

GAO Contact

Dwayne E. Weigel (202) 512-6876

Acknowledgments

In addition, Michael J. Rahl, Carolyn K. McGowan, John Fretwell, Peggy Smith, Cynthia Norris, Doreen S. Feldman, and Barbara Timmerman made key contributions to this report.

Related GAO Products

Radiation Standards: Scientific Basis Inconclusive, and EPA and NRC Disagreement Continues (GAO/RCED-00-152, June 30, 2000).

Low-Level Radioactive Wastes: States Are Not Developing Disposal Facilities (GAO/RCED-99-238, Sept. 17, 1999).

Nuclear Regulation: Better Oversight Needed to Ensure Accumulation of Funds to Decommission Nuclear Power Plants (GAO/RCED-99-75, May 3, 1999).

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Exhibit D

Indian Point Probabilistic Safety Study

Overview and Highlights

Power Authority of the State of New York
Consolidated Edison Company of New York, Inc.

1982

INTRODUCTION

In the past decade, society has grown increasingly aware of the direct and indirect risks that can accompany technological advancements. This awareness has led to new laws, new regulations, and new scientific methods for measuring technological risks. These new techniques attempt to quantify the two elements that make up "risks" – the likelihood of the damage occurring and the magnitude of any potential damage – or in risk assessment terms, the "probabilities" and the "consequences." These two components of risk – probabilities and consequences – cannot be separated; both are essential to decisions about benefits and the relative merits of alternative courses of action. By calculating both components of technological risk as precisely as possible, society can more knowledgeably compare the relative risks of competing technologies. Then, the risk of a technology in comparison to its benefits can be examined.

The energy production industries, particularly nuclear power, have been at the forefront of these advances in risk assessment. Nuclear power has adopted an advanced, sophisticated approach in detecting and measuring risks which has furthered our understanding of nuclear power plant safety. When all other forms of energy are similarly evaluated, a truer picture of the tradeoffs in energy decisions will emerge.

The purpose of this overview is to present some of the highlights of an extensive safety study performed on Indian Point Units 2 & 3. Since the study is a state-of-the-art investigation using sophisticated scientific tools, this overview provides some perspective for the general readership. It includes a discussion of nuclear power plant safety features and reactor safety analyses. Then, it describes a methodology called "probabilistic risk assessment" (PRA) followed by highlights of the Indian Point Probabilistic Safety Study.

NUCLEAR POWER PLANT SAFETY

In decisions to license, build, and operate all nuclear power plants, the issue of safety dominates. Operators of nuclear power plants must demonstrate to the Nuclear Regulatory Commission (NRC) – the independent Federal agency responsible for licensing and regulating nuclear facilities – that each plant is designed and constructed with adequate safety features. Most of these safety features have one overall objective: to prevent or minimize accidents which can result in offsite radiation exposure or release of radioactive material from the plant.

Reactor Design Features

Several physical barriers to prevent radioactive materials from escaping to the environment are designed into every nuclear power plant. They include:

- ***Fuel Rods***. The tubes, or fuel rods which hold uranium fuel pellets, are made of a strong alloy called zircaloy which helps prevent the contained solids and gases from spreading through the reactor coolant system.
- ***Reactor Vessel***. Surrounding the core of fuel rods is a reactor vessel some 8 inches thick manufactured of alloy steel to the most rigorous standards and lined with stainless steel.
- ***Containment Building***. The reactor and its coolant system are surrounded by a massive concrete and steel building which is specially designed to prevent radioactive materials from reaching the environment in the event that piping systems should leak or break. The concrete in the containment is typically some 3 feet thick and lined with welded steel plate.

In addition to these physical safety barriers, nuclear power plants are designed and built with multiple and diverse safety systems. Outside the plant and at the site boundary, sensitive monitoring and surveillance instruments are installed to detect radiation releases.

Scientists are able to detect and measure radiation even in minute amounts better than virtually any other substance known to man. According to the Committee on the Biological Effects of Ionizing Radiation (BEIR) of the National Academy of Sciences, the average American receives about 100 millirems (a millirem – or one-thousandth of a rem – is a standard unit of radiation dose measurement) each year from background radiation. Natural background radiation comes from the sun, minerals in the earth, and other naturally radioactive elements in the air and in our food. Nuclear power plants and related activities contribute on the average only 0.3 millirems each year to natural background radiation levels under normal operating conditions.

Nonetheless, an accidental release of radioactive materials to the environment with higher exposure levels remains a remote possibility. Because this potential impact upon public health and safety exists at all, emergency plans have been developed and studies are done to continually improve the safety systems in nuclear power plants.

Reactor Safety Studies

Safety analyses are performed for every nuclear power plant before it begins operating. These analyses determine whether the plant owners and operators have taken the appropriate precautions for safe operation of the plants. The techniques for conducting these studies have been refined over the years as the nuclear industry gains more experience. These refinements and improvements are made possible by a growing body of information about the performance of the designed safety features, the reliability of components, and the adequacy of safety margins for different systems and components. Further refinements are made possible by advances in computer technology – the ability to process and analyze large quantities of information to the smallest detail – and in the analytical techniques used by scientists to unravel complicated series of events and to estimate the impacts of those events.

From the early days of the nuclear industry – more than 25 years ago and 1,500 operating years of experience worldwide – safety thinking centered around the multiple-barrier approach, the physical layers of protection (such as the containment) and the series of backup safety systems (such as emergency core cooling) in case the primary system should malfunction. This safety concept is termed "defense in depth."

Observing "defense in depth" guidelines led to design requirements for nuclear plants that included hypothetical problems called design basis accidents and maximum hypothetical accidents. Engineers had to consider what damage could be caused by, for example, a loss of coolant to the reactor vessel, an earthquake, an airplane crash, a fire or pump failure. They then designed the different parts of the plant to withstand such accidents if these events were to occur.

Since physical simulation of each hypothetical accident is not feasible, additional calculations were made for the most serious possible damages to the plant. These "upper bounding" calculations helped ensure that the best engineering judgments about safety — for example, how much stress a piping system could take in the event of an earthquake — incorporated extra safety margins.

The "defense in depth" philosophy has served the cause of nuclear safety well. Carried to an extreme, however, it can be counterproductive. The introduction of unnecessary complexity could cause a net reduction in safety instead of the expected increase in levels of protection.

Therefore, with the accumulation of a substantial body of nuclear operating experience, scientists determined that tools other than "upper bounding" calculations were needed to make more accurate and realistic safety decisions about nuclear power plants.

Leaders in the field began to look at some of the new scientific tools that other industries — aerospace and defense, for example — were developing to deal with their own questions about safety, performance, and the risks involved. These tools seemed to suit many of the same issues that the nuclear industry confronted. Yet much more work needed to be done to achieve the accuracy and realism that the nuclear industry desired. Experts from a number of different fields pooled their knowledge to address the problem: how can we systematically evaluate even the most improbable accidents to determine the risk they could present to public health and welfare?

The Reactor Safety Study, commissioned by the NRC and directed by Dr. Norman C. Rasmussen of the Massachusetts Institute of Technology, was the first comprehensive study of the accident-related risk of nuclear power plants. Published in October 1975 after three years of work, it was the first attempt to quantify the risks resulting from nuclear power plant operation. It enabled a systematic classification of accidents according to their possible frequency and the possible consequences that could result.

The benchmark Reactor Safety Study report was thoroughly reviewed and critiqued by numerous groups in the years following its publication. The Lewis Report, an evaluation performed for the NRC by the Risk Assessment Review Group, contains both praise and criticism for the original study.

According to the Lewis Committee, the Reactor Safety Study was a significant improvement over earlier attempts to calculate the risks of nuclear power. It introduced a workable accident classification scheme and applied the rules of mathematical probability theory in order to quantify risks. It evolved "event tree" and "fault tree" procedures – described later in this report – to quantify the frequencies with which accidents could happen. It also examined a broader range of potential health effects. In addition to expressing risk in terms of injuries and fatalities that could occur immediately following an accident, the Reactor Safety Study considered the delayed effects of an accident by estimating latent fatalities and cancers. The Lewis Committee also criticized the Reactor Safety Study primarily for its lack of an adequate data base on which to perform some of the analyses and the way uncertainties in the results were portrayed.

Advances in reactor safety analysis since the Reactor Safety Study include:

- More extensive operating data and improved methods for handling data, including the treatment of uncertainty.
- Better documentation and models for systems to reflect the interaction of reactor operators and accident conditions.
- More comprehensive treatment of core damage and the response of the containment during an accident.
- More accurate modeling of specific conditions of the plant site, including initiating events.
- Improved methodology for assembling the results and working backwards to specific risk contributors.

The more recent probabilistic safety studies in this country and Europe built on the foundation of the Reactor Safety Study, addressed its criticisms and incorporated these advances. The Indian Point study, in particular, represents the current state of the art.

UNDERSTANDING PROBABILISTIC RISK ASSESSMENT

Probabilistic risk assessment is considered the most advanced way to make practical decisions in a highly technical, complex society where risks cannot be eliminated, but must be controlled. It helps us understand which things are more likely than others to go wrong and provides a framework for deciding what, if anything, should be done about them.

People have sought ways to assess risk for centuries. Examples can be found in the insurance industries, the financial community, and others that deal with consumer protection. The challenge has been to assess risk systematically and to take into account unforeseen circumstances.

PRA allows you to do just that. Any accident can be examined, regardless of its likelihood. Uncertainties are clearly identified in the process. Analyzing "frequencies of occurrence" allows you to tag the most important accident scenarios among the many thousands examined. Human errors can be factored into the calculations as can complications unrelated to the accident itself that could change the levels of risk involved.

The use of PRA techniques is not limited to the nuclear industry. Others are already using a number of PRA techniques. That trend is expected to continue, with the nuclear industry in the vanguard.

Simply put, the PRA methodology asks three basic questions:

- What could go wrong?
- How likely is it that this will happen?
- If it happens, what are the consequences?

The answers to those questions help planners and decision makers to determine what, if anything, should be done to reduce the likelihood that a particular type of accident could happen or to reduce the level of damage that could occur. The answers help isolate the factors that pose the most substantial chance of adversely affecting public health and welfare.

What Could Go Wrong?

In analyzing risk, we are attempting to understand the effects of taking or failing to take a certain course of action. Since an outcome of a course of action involves a whole sequence of events, the term "scenario" is generally used in place of "outcome."

Developing a "scenario" begins with identifying an event that could precipitate an accident. For example, lightning striking the roof of a building could start a fire which destroys the building. The lightning strike is called the "initiating event" or beginning of an accident sequence.

The next step in developing a scenario, after identifying an "initiating event," is to frame a series of questions that ask: "If such and such occurs, *what could happen next?*" Two kinds of answers are given in response to the question: one assumes that a safety barrier erected to prevent further damage from the initiating event works; the second answer assumes that the safety barrier fails.

Using our lightning strike analogy, if the lightning strikes the building, it could hit the lightning rod installed on the roof (the safety barrier works) or it could hit another part of the roof, such as an air conditioning unit (the safety barrier fails). If it hits the air conditioning unit, what could happen next? The regulator on the unit could shut itself down because of the power surge (the next safety barrier works) or the regulator could malfunction and cause a small fire to start in the wiring system (safety barrier fails). And so on. The questioning continues in this manner until every sequence of events that could result from the initiating event is identified.

The process of identifying all of the events in a particular sequence, and assuming that a safety barrier either works or fails, is called building an "event tree." In PRA, complete event trees are developed for all conceivable initiating events.

The next step in answering the basic question, "What could go wrong?" is to determine *how* each of the failures in the succession of safety barriers can happen. How, for example, did the fire start in the wiring system? This requires an examination of the subsystem or components that make up the safety barrier in order to identify those factors which could lead to failure of an entire barrier system. The results of investigating how the failures can happen are diagrammed on a "fault tree."

Fault trees are used to determine the likelihood of failure of the safety systems identified in the event tree. In developing the fault trees, consideration is given to component failure, maintenance action, human error, and other causes. Each system is examined in sufficient detail to determine the *frequency* of failures by looking at the reliability of each of the parts involved.

How Likely Is It That This Will Happen?

The likelihood of something going wrong is based on data about a particular element in the fault tree. The data may include, for example, operating records on equipment or systems.

If there is a large amount of such data, the likelihood of success or failure can be calculated with a high degree of certainty, or "confidence." When there is less data, the calculated frequency, or likelihood, is more uncertain.

These uncertainties are described in terms of "probabilities." In the context of this study a confidence level of 90% implies a probability that the parameter in question – frequency of occurrence of a particular event, for example – does not exceed a given value.

PRA studies include a rigorous mathematical assessment of uncertainty. The uncertainty of each element in the analysis is computed and is included in the final result. Thus, the likelihood of an event occurring is expressed in terms of frequency of occurrence *and* the level of confidence regarding the frequency. This format of communicating uncertainty is called the "probability of the frequency of occurrence."

PRA studies may consider literally millions of scenarios and their corresponding probability of the frequency of occurrence. These probabilities are tabulated individually and the results are usually presented on a graph.

If only one confidence level or "probability level" is used, the results would form one curved line. It is more common to look at several confidence levels:

- The 1 in 10 chance, or 0.10 probability
- The 5 in 10 chance, or 0.50 probability
- The 9 in 10 chance, or 0.90 probability

These results are normally computed on the same graph (three curved lines) and are called a "family of curves." The interval between the top curve and the bottom curve is the uncertainty band.

To translate these confidence statements into everyday language, consider the frequency at the 0.50 probability level as a "best" estimate and the frequency at 0.90 probability as an "upper bound." Upper bound estimates mean that "it is almost certain that the frequency of occurrence will not exceed this value." For purposes of communication, therefore, discussions of risk assessment results will use statements such as "the *best* estimate of the frequency of this scenario is once every 10,000 years and the *upper bound* is once every 1,000 years."

If It Happens, What Are the Consequences?

The accident consequences of paramount concern are those affecting people's health. Consequences of accidents are evaluated using extensive computer programs to model accident scenarios, the conditions of the region around the site of the accident, population information, and any other relevant factors including protective measures that could offset some of the damage.

The results of the analysis of accident consequences are expressed as "damage levels", e.g., numbers of injuries, numbers of fatalities. The consequence analysis is combined with the plant and containment analyses to arrive at the "probability of frequency of different levels of damage." The combined results of damage levels with frequency of occurrence are translated in graphic form into risk curves.

The risk curves from a PRA convey considerable information, for example, what is the frequency of accidents resulting in any immediate fatalities, or what is the frequency of accidents resulting in 100 or more injuries. The degree of confidence (probability) with which the result is stated (10%, 50%, or 90%) is also conveyed.

Frequencies of occurrence are not predictions. They are expressions of the collective knowledge and experience of the experts who performed the probabilistic risk assessment. Frequencies of occurrence suggest what the odds (probabilities) are of something actually happening, and thus provide a basis for comparisons with other risks.

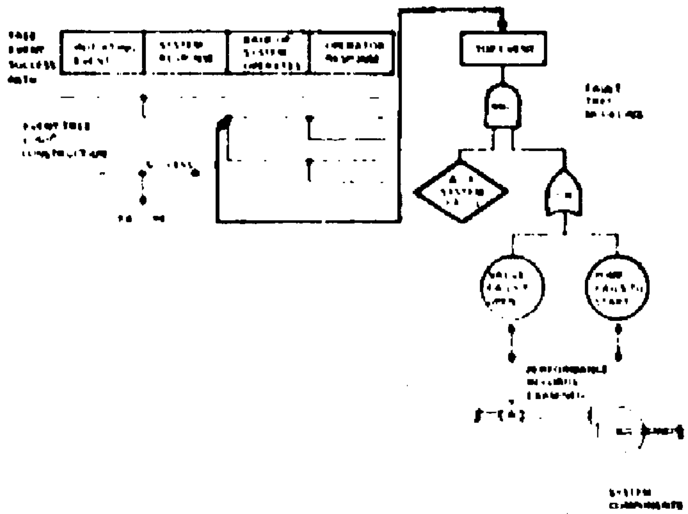
The risk curves link the likelihood that the accident could happen with the potential consequences of an accident. This is the proper way to view risk — probability coupled with consequences.

PROBABILISTIC RISK ASSESSMENT: SOME GRAPHIC ILLUSTRATIONS

The PRA methodology involves a rigorous process that organizes a vast amount of data through highly detailed analyses. The most effective way to display the key steps, the interrelationships, and the final results is graphically. These are some very simplified examples of what is actually done in a fully developed study.

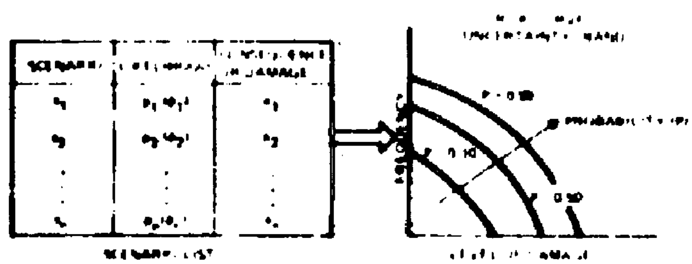
Quantifying Accident Sequence Probabilities

Event trees diagram what could happen as a result of an initiating event which could lead to an accident. Branches of the tree illustrate the success or failure of the series of safety barriers and frame the answer to the question "what could happen next?" When a failure is identified, it becomes the "top event" in a fault tree analysis. Fault trees trace the failure back to its root causes, primarily using reliability performance information, to determine how the failure occurred.



Risk Results

The list of accident scenarios, their likelihood of occurrence (including uncertainty), and their consequences number in the millions in a risk assessment study. After the confidence levels are determined, the computerized list format is translated into risk curves. Levels of damage (or consequences) are expressed in terms of numbers of people affected and the frequency of an accident occurring that could cause that kind of damage. Confidence levels for the results are labeled on the curves lines: 10% probability, 50% probability, and 90% probability. The interval between the 10% curve and the 90% curve is called the "uncertainty band" which shows the minimum and maximum potential consequences of an accident. The information in the scenarios list could be used to add more curves at other confidence levels if it were desired.



THE INDIAN POINT PROBABILISTIC SAFETY STUDY

A comprehensive safety study using PRA techniques was conducted for Indian Point Units 2 & 3, beginning in January 1980. A team of more than 50 experts was involved in the project, including nuclear engineers; systems analysts, probability theorists, mathematicians, risk analysts, computer specialists; experts in thermohydraulics, chemistry, radiological effects, meteorology, seismology and wind; and nuclear power plant operators and designers. This work was reviewed and discussed with an independent review board. The final study report, more than 6,000 pages long, was submitted to the U.S. Nuclear Regulatory Commission in early 1982.

The Indian Point study has two basic purposes:

- To provide a thorough assessment of public risk resulting from the operation of Indian Point.
- To identify the dominant contributors to that risk in terms of plant design and operation. In that connection, the study postulated a variety of equipment malfunctions including progressive failures of multiple engineered safeguards leading to melting of the reactor core and failure of the containment building.

The study team began by collecting extensive information from several sources:

- Specific Indian Point operating data, covering the plant and the site. Plant data included, for example, component performance records, maintenance duration reports, and initiating event analyses. Site data included comprehensive examinations of meteorology, terrain, and demographics.
- Operating data from other nuclear power plants. Numerous data sources were analyzed to establish a comprehensive data base. Sources of data included (1) Licensee Event Reports and the NRC data summaries of these reports covering diesel generators, pumps, valves, and control rod drives, (2) the IEEE Guide to the Collection and Presentation of Electrical, Electronic, and Sensing Component Reliability Data for Nuclear Power Generating Stations, (3) the Reactor Safety Study, (4) the Nuclear Plant Reliability Data System, (5) the EPRI reports on Frequency of Anticipated Transients, and (6) the Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications.
- Expert judgment on equipment performance and accident initiators. Experts and their resources contributed additional insight and information about equipment performance and specific events that could initiate an accident or alter its course.

These data were examined using the PRA methodology discussed previously. In order to assess the possibility that public health could be endangered by an accident at Indian Point, the study identified accident sequences that could lead to release of harmful levels of radioactivity and isolated the dominant contributors to risk contained in those sequences.

The investigative process was exhaustive:

- Literally hundreds of thousands of accident scenarios were developed using the event tree/fault tree approach. Information about reactor operations and reliability of equipment was incorporated in the scenarios. These event trees and fault trees were used to evaluate various sequences leading to release of radioactivity.
- In order to isolate dominant risk contributors, initiating events from both internal and external causes were analyzed. Internal causes included plant malfunctions called "transients" and failures in heat removal systems such as loss of coolant accidents (LOCAs) which could lead to melting of the reactor core. External causes included earthquakes, fires, high velocity winds, tornadoes, floods, and aircraft accidents. Analyses of initiating events and accident sequences were not limited to hardware concerns; operator interaction with the plant systems and human response under accident conditions were also assessed.
- The response of the reactor core and containment under different core melt conditions was analyzed in extensive detail. The form and state of the damaged core and its interaction with structural materials, air, water, steam, and other reaction products were considered. The progress of core melt conditions was examined carefully; the pressure changes during a core melt and fluctuations in heat loads were quantified to define containment response; and release conditions for radioactive material were identified.
- The region around Indian Point was modeled, including information about population distribution and meteorological conditions. This information helped establish the level of risk which is partially dependent on wind speed and direction, the portions of the surrounding communities potentially affected, dispersion of radioactive material, and the like.
- After the dominant risk contributors were identified, along with their causes and probable frequency of occurrence, estimates were made of the potential damage to public health and safety. These estimates were compiled and displayed graphically as a family of risk curves which indicates the confidence level attached to the estimates.

Public Health Effects

The results of the Indian Point Probabilistic Safety Study focus ultimately on public health effects. The risks to public health discussed in this overview are early, or "acute," fatalities occurring within a short time after exposure, non-fatal radiation injuries due to exposure, thyroid cancers (most of which are treatable and non-fatal), and latent cancer fatalities occurring over a 30 year period. The results are highlighted here for three levels – any effect, 100 effects, and 1,000 effects. In like manner, frequency of occurrence results have been computed for other levels of effects.

The results are also presented as "best" and "upper bound" estimates. By presenting two estimates, this analysis provides a more comprehensive picture of risk than would be the case if only a single health effect, a single level of effect, or a single confidence level were depicted.

Indian Point Unit 2. The most significant health effect, in terms of near-term impact, is acute fatalities. The estimates vary depending on the level of consequences analyzed. The best estimate for any effect is once in 17 million (17 million)* years of reactor operation. The best estimates of frequencies of occurrence for 100 and 1,000 effects are once in 100 million (4.8 million) years and once in a billion (29 million) years, respectively.

For radiation injuries, the best estimate for any effect is once in 370,000 (59,000) years. The best estimates for 100 effects are once in 2.9 million (290,000) years, and for 1000 effects once in 10 million (2.9 million) years.

In addition to the immediate health effects of an accident, delayed effects were also examined. For example, the best estimate of any thyroid cancers occurring is once in 2,500 (1,000) years of reactor operation. The best estimates for 100 effects are once in 5,900 (1,400) years and for 1,000 effects once in 12,000 (2,700) years.

Finally, the question of latent cancer fatalities occurring over a 30 year period was investigated. The best estimate for any effect is once in 3,000 (1,000) years. The best estimates for 100 effects are once in 5,000 (1,400) years, and for 1,000 effects once in 10,000 (2,400) years.

Indian Point Unit 3. The results for Indian Point 3 differ somewhat from Unit 2 due to some differences in design and equipment. The best estimate for any acute fatality is once in 8.3 million (10 million) years. The best estimates for 100 effects are once in 30 million (45 million) years, and once in 6.3 billion (290 million) years for 1,000 effects.

For radiation injuries, the best estimate for any effect is once in 2.6 million (130,000) years. For 100 effects, the best estimate is one in 20 million (2.4 million) years, and for 1,000 effects, the best estimate is once in 300 million (28 million) years.

The best estimate for any latent thyroid cancers occurring is once in 12,000 (3,300) years. The best estimates for 100 effects are once in 63,000 (7,700) years, and for 1,000 effects once in 100,000 (12,000) years.

The best estimate for any latent cancer fatalities occurring over a 30-year period is once in 20,000 (5,000) years. The best estimates for 100 effects are once in 55,000 (8,000) years, and for 1,000 effects once in 100,000 (12,000) years.

The likelihood that an accident would cause any public health consequences is remote. Upper bound estimates indicate that an accident causing any acute fatality is once in 17 million years and that an accident resulting in 100 or more latent cancer fatalities is once in 1400 years. Information on accidental fatalities and latent cancer fatalities from *non-nuclear* causes provides some perspective on these potential health effects. For example, every year, based on the national average, there will be at least 100 accidental fatalities within a 10-mile radius of Indian Point and at least 30,000 cancer fatalities within a 50-mile radius of the plant, all unrelated to nuclear power.

The Results in Perspective

The risk assessment for Indian Point identified the elements of an accident that would need to be present for any fatalities to result.

- *The Reactor Core Must Melt.* Coolant must be maintained in the reactor core to avoid fuel damage. Therefore, nuclear plants contain several backup cooling systems that can be called on to cool the core if the primary system should stop functioning. Only if these "emergency core cooling systems" should fail would some of the fuel rods melt or be damaged, causing a release of fission products into the reactor vessel and reactor coolant system.

  If there should be a core melt, this by no means suggests that there will necessarily be a significant release of radioactivity to the environment outside the plant. The containment structure of a nuclear plant is designed to contain the radioactive material and prevent such releases. A core melt by itself constitutes no real threat to public health and the study indicates that most core melts would be contained without significant release of radioactive material to the environment.

- *The Containment Must Fail or Be Bypassed.* If the containment serves its function, a core melt would only lead to some leakage of radiation around some of the piping passageways that connect the containment with other buildings in the plant. The risk of those small leaks would be of little or no consequence to the public health.

* The numbers in parentheses are the upper bound estimates.

If the containment were to fail, the amount and type of risk to public health would depend upon conditions such as wind speed and direction, how quickly the radioactive "plume" is dispersed, and the effectiveness of protective steps like sheltering or evacuation. The possibility of bypassing the containment was also examined. Out of all accident categories studied for Indian Point, only about 1 in 1,000 core melt accidents leads to a release which could potentially cause any early fatalities.

A study with the scope and level of detail of the Indian Point safety assessment produces an extremely large body of information and results. Thousands of accident scenarios have been identified and their likelihood and consequences discussed. This overview presents only the key findings about public health effects and the safety of Indian Point.

The application of risk assessment to nuclear safety analyses, while adding immeasurably to our understanding of nuclear safety, has perhaps colored our perception of what the risks truly entail. Because comparable assessments have yet to be performed to the same level of detail for other energy sources and other industries, nuclear safety is being weighed in a vacuum.

Risk analyses in one sense may counteract their intended purpose. Events which are beyond reasonable belief tend to assume a degree of reality when they are analyzed in minute detail. Detailed analyses make people aware of possible hazards which in all probability will never result in injury. Ironically, risk analyses may demonstrate that certain risks are exceedingly remote yet fear of those same risks may increase by that very demonstration. The initial perception of "rare and remote" evolves into a growing uneasiness that "something just may happen." On the other hand, far greater risks unrelated to nuclear power may not be viewed with concern simply because they have not been so intensively investigated. Nuclear power – its safety and its risks – should be considered in that context.

Indian Point Probabilistic Safety Study

Volume 1

Copy No. 15

PREFACE

This report is a Probabilistic Safety Study of Indian Point Units 2 and 3, owned and operated by the Consolidated Edison Company of New York, Inc., and the Power Authority of the State of New York, respectively. The study includes: a discussion of probabilistic risk assessment methodology; plant, containment and site analyses; an analysis of initiating events including events external to the plant; an identification of the dominant contributors to risk; and a quantitative statement of the level of safety at the Indian Point nuclear power plants.

This study was prepared by Pickard, Lowe & Garrick, Inc., Westinghouse Electric Corporation, and Fauske & Associates under the supervision of the Utilities.

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METHODOLOGY

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SECTION 0

METHODOLOGY

0.1 INTRODUCTION AND PURPOSE

The purpose of this section is to give an overview of the basic methodology of risk analysis used in this safety study. Various individual segments of this methodology are developed in greater depth in later sections. The emphasis here is on the overall structure and flow of the process and on how the various segments fit together. The section is divided into three major parts: Part 1, Definition of Risk; Part 2, Modeling and Analysis; and Part 3, External Events.

To do a risk assessment, we obviously must first agree upon a precise and usable definition for the word risk. This is the purpose of Part 1. This part begins (in Section 0.2) by discussing some qualitative aspects of the notion of risk as used in this study. It then proceeds, in Section 0.3, to give a quantitative definition of risk in terms of a set of envisioned scenarios, or sequences of events, together with the probability and damage associated with each. This definition is called the "Level One" definition of risk. Section 0.4 explains the sense in which the word "probability" is used in this definition. For several reasons, given in this section, it is desirable to expand the Level One definition so that it may encompass some further subtleties of the idea of risk. Section 0.5 gives such an expansion and refers to it as the "Level Two" definition of risk. This latter definition then becomes the basis for the methodology of the study and the format for the presentation of the results.

Once the definition of risk is established, Part 2 then deals with the methods used to actually model and quantify the risk in a nuclear plant. Thus, with risk now defined fundamentally in terms of a list of scenarios, the next question is: "How does one identify and structure the scenarios on the list?" This question is addressed in Section 0.6. The key analytical device here is the "event tree" which is a structured presentation of the myriad of scenarios branching out of any given initiating event. Another key device is the notion of "pinch point" which allows the event trees to be partitioned into three segments: "plant," "containment," and "site."

With the scenarios identified and structured in terms of event trees, the next step is to determine frequencies of the various paths through the trees. This is done in terms of "split fractions" at the branch points of the tree in the manner discussed in Section 0.7.

Section 0.8 then addresses the question of assembling the information from this myriad of scenarios into a final presentation of the risk. The method chosen for this assembly takes maximum advantage of the structural properties of the list. Indeed, these properties and this method allow the results to be presented in a very clean and compact matrix form. This form also provides great visibility into the performance of various parts of the plant. Thus any potential problems can be readily seen and the effects of proposed hardware or procedure changes readily evaluated.

Sections 0.2 through 0.8, therefore, describe the definition of risk in terms of a list of scenarios; the identification, structuring, and quantifying of the list; and the assembly into a final presentation of risk curves. This much may be considered the "main stream" of the methodology. The remaining sections describe the numerous tributary flows into this stream.

Thus, Sections 0.9 and 0.10 describe the determination of the split fractions in terms of the frequencies of more basic "elemental" events. Section 0.11 describes the site modeling and consequence analysis, given releases of radioactivity from the containment. Sections 0.12 and 0.13 review some of the basic mechanics of probability distributions and probabilistic calculations. Section 0.14 outlines the sources of information about the elemental events and the basic mathematical principle (Bayes' theorem) for combining these different types of information into probability distributions for the frequencies of elemental events. Section 0.15 discusses the treatment of an important type of elemental event; human error. Section 0.16 discusses some further aspects of the process of combining "elemental" probability distributions during the course of system analysis. Several important pitfalls are identified here relating to the dependence of probability distributions and the use of lognormal curves.

Part 3, External Events (Sections 0.17 through 0.20), provides detail on the methods used for seismic, wind, and fire analyses; and a review of the methodology with respect to the question of completeness.

7.6 AIRCRAFT ACCIDENTS

7.6.1 AIRPORTS AND AIRWAYS

The airports and airfields within approximately 25 miles of the site are listed below (Reference 7.6-1).

	Airport/Location	Distance From Plant (miles)
1.	Danbury, Danbury, CN	26
2.	Greenwood, Greenwood Lake, NJ	22
3.	Mahopac, Mahopac, NY	12
4.	Orange County, Montgomery, NY	22
5.	Peekskill Seaplane Base, Verplanck, NY	1
6.	Ramapo Valley, Spring Valley, NY	13
7.	Stewart Air Force Base, NY	17
8.	Warwick, Warwick, NY	18
9.	Westchester County, NY	18

The three closest airports are Mahopac, Ramapo Valley and Peekskill Seaplane Base. The other airports are more than 17 miles from the plant.

Mahopac Airport is a small airport for general aviation. It has a turf runway 1,800 feet long and is only operated during daylight. It normally supports approximately 15 flights per day, with an annual peak of perhaps 3,500 operations. The largest aircraft using the airport is a Piper Aztec (Reference 7.6-2).

Ramapo Valley Airport is a small, private airport for general aviation. It has a 2,200 foot long runway. Generally, it supports fewer than 50 flights per day. The largest aircraft presently based there is one Cessna 310 (Reference 7.6-3).

The Peekskill Seaplane Base is a general aviation airport at Verplanck Point, about 1-1/2 miles south of the Indian Point plant. There are about 20 aircraft normally stationed in the parking area on the edge of the Hudson River in addition to itinerant aircraft. The maximum size aircraft operating from the base is a four passenger Grumman seaplane with a weight of 5,500 pounds (Reference 7.6-4). The designated seaplane takeoff and landing pattern on the river is equivalent to runway 16/34 (see Figure 7.6-1). While these azimuths are generally southeast/northwest and parallel with the shoreline south of Verplanck Point and because of the short takeoff and landing distances required by these small aircraft, takeoffs are made on almost any azimuth south of the high voltage transmission lines crossing of the Hudson River. These lines serve the Orange-Rockland Utility Company.

There are between 3,000 and 4,000 takeoff and landing operations per year near the seaplane base, with a summertime peak of about 500 operations per month. A 100-foot high hill between the designated northerly takeoff or landing pattern and the Indian Point plant affords some protection and separation from low flying aircraft.

The airways within 12 miles of the plant site and the number of flights recorded by the FAA for each on a peak day in 1977 are indicated in Table 7.6-1. Aircraft using several of the nearby airports are vectored on courses that pass within about 5 miles southeast of the plant site. Airways or direct aircraft routings for which the edge of the airway is within 2 miles of the plant site are considered to be contributors to the hit probability estimate (Reference 7.6-5).

As seen in Figure 7.6-2, there is only one designated airway that lies within the 2-mile criteria. It is V157, which in this segment runs between the VORTACs at Kingston and Colts Neck, generally a north/south route. The centerline of this airway is 2 miles east of the plant site. The next closest designated airways are V292, about 8-1/2 miles south of the plant and running generally east/west; and J37, about 8-1/2 miles east of the plant and running generally north/south. The nearest edge of each of these airways is about 4-1/2 miles from Indian Point, so these airways are not considered in the overflight analysis.

There are two direct routings in the vicinity of the plant that are sometimes used in lieu of a designated airway. One of these, HUO-CMK, is a route between the Huguenot and Carmel VORTACs, with a centerline 5 miles northeast of the plant. The other is HUO128, the 128° radial out of Huguenot VORTAC, with a centerline 5 miles southwest of the plant. In each of these cases, the edge of the route is about 1/2 mile from Indian Point and, therefore, these routings are included in the overflight analysis.

7.6.2 AIRCRAFT HAZARDS ANALYSIS

The Mahopac and Ramapo Valley Airports do not present a landing or takeoff hazard to the plant because of the small size of the aircraft there and the large distance from the plant. The nearness of the Peekskill Seaplane Base to the plant, however, warrants a closer examination.

The probability of an aircraft operating from the seaplane base hitting the plant during landing or takeoff is based on the algorithm and aerial crash density given in the NRC Standard Review Plan (Reference 7.6-6).

The algorithm is

$$P = CNA$$

where

P = annual probability of a plant strike by an aircraft

C = aerial crash density for the appropriate category of aircraft (crashes per square mile of projected facilities area)

N = number of annual operations on the runway

A = area of the vulnerable structures whose failure could lead to core melt (square miles)

The critical facilities of concern for a light aircraft crashing at the site are the following:

1. Impact with the feeder high voltage line from Buchanan substation and a loss of offsite power to either or both units.

2. Impact on the station auxiliary transformer (loss of offsite power) of either Unit 2 or Unit 3.

3. Impact on the unit auxiliary transformer (loss of power from unit generator or offsite power) of either Unit 2 or Unit 3.

4. Impact on the Unit 2 diesel generator building (loss of diesel generator power).

5. Impact on the Unit 2 control building/control room (loss of manual control).

6. Impact on the Unit 1 superheater stack resulting in its collapse onto the Unit 2 diesel generator building (loss of diesel generator power) or onto the Unit 2 control building (loss of manual control), or onto the Unit 3 condensate storage tank (loss of condensate water).

7. Impact on the steam and feedwater piping between the turbine building and containment building (loss of steam generator cooling) of either Unit 2 or Unit 3.

8. Damage to the RWST or CST (loss of refueling water or condensate storage water) of either Unit 2 or Unit 3, or to the city water storage tank (backup to the CSTs).

9. Impact at the control room air intake (fuel explosion and fire in duct work to control room) of either Unit 2 or Unit 3.

10. Impact on the diesel fuel transfer pumps (loss of fuel to one or more diesel generators) of either Unit 2 or Unit 3.

11. Impact on the service water pumps of either Unit 2 or Unit 3.

12. Impact on the Unit 2 PAB top story (loss of MCCs for safeguard valves and of CCW surge tank or heat exchangers).

Most of the listed facilities, would be protected from a direct hit by a low trajectory northerly or southerly bound aircraft by a larger building, such as the turbine, containment, or primary auxiliary buildings. The control building is the only single building which, if hit, could lead to core melt. Impact by a low-flying errant plane on the Unit 2 control building does not appear to be possible because of the protection afforded by the Unit 2 and Unit 3 containment and turbine buildings and the Unit 1 superheater building. The concrete Unit 3 control building is protected from all but northbound aircraft, but even in that case, protection to the building contents is afforded by the building's concrete walls. Impact with the Unit 3 control room air intake duct, an explosion of the aircraft's fuel tank or the release of its contents, and release of toxic gases into the control room might be postulated for a southbound aircraft. The intake area, however, is well protected by the Unit 3 containment building, making this scenario extremely improbable. Impact from the south with the Unit 1 superheater stack could cause the stack to collapse onto the roof of the Unit 2 control room. However, considering the probability of missing the adjacent buildings, and considering the projected stack area, the probability of hitting the stack at the plant and causing it to fall on the small area of the control building is extremely small.

For general aviation aircraft and runway distance to the plant of a little over 1 mile, $C = 1.5 \times 10^{-7}$. The maximum exposure area, (A), for the Unit 2 control building is approximately 0.0004 square miles. Given that annual operations (N) are equal to 4,000, a figure that includes many flights off the designated runway azimuth, the Unit 2 control building hit probability, P, would be 2.4×10^{-7} per year. The hazard for Unit 3 is substantially less.

The east bank tower of the Orange-Rockland transmission line which crosses the Hudson River near the plant is at Elevation 495'. Three sets of transmission lines span the river from the tower, with the lowest at 165-foot elevation at midspan. If a plane were to hit the transmission line it would be about 4,000 feet from the Unit 3 facilities. The plane's velocity would be low and its approach angle under this hypothesis would be no greater than about 6 degrees from the horizontal. At this low angle, and given a loss of engine power resulting from the impact with the transmission line, it is highly unlikely that the plane could even reach the plant. Further, the intervening hill provides protection.

The probability of an aircraft using a federal airway or other FAA air traffic controlled path and accidentally hitting the Indian Point plant is also estimated. The probability of an aircraft hitting the plant is based on the methodology used by the NRC (Reference 7.6-6). For airway traffic, the hit probability algorithm is

$$P = CNA/W$$

where

P = the probability of a hit by an aircraft, per year

C = the inflight accident rate, per mile flown

N = the annual number of flights on the specified airway

A = the effective area of the structures which could be hit, in square miles

W = the width of the airway, in miles

A study (Reference 7.6-7) was performed to determine the vulnerability of the Unit 2 containment to aircraft crashes. The study concluded that for planes up to the 727 class, and for striking velocities of up to 300 knots, the engine penetration into the reinforced concrete building would be less than 6 inches and scabbing thickness would be less than 18 inches. For the 54-inch wall and 42-inch dome thicknesses, there would not be a breach of containment. Based on the analysis, we conclude that for concrete wall thickness less than 8 to 10 inches and for exterior masonry walls, there could be scabbing of the interior surfaces. For metal wall or roof coverings or vessels, it is likely there would be penetration.

The area which could be hit, represented by all potentially vulnerable structures for each unit, is estimated to not exceed 0.01 square miles including an allowance for the shadow and skid areas.

The NRC Standard Review Plan suggests the use of an inflight accident rate of 3.0×10^{-9} per mile flown and this rate is used.

The NRC Standard Review Plan suggests the width of the aircraft hit area (in order to calculate aerial crash density) be taken as the width of the airway. This corresponds with the assumption of uniform hit density throughout the entire width of the airway. The plan also suggests that if the area being considered lies outside of the full width of the airway, the equivalent width of the hit region should be increased by twice the distance from the edge of the airway to the impact area. The standard airway width is 8 nmi (±4 nmi about the centerline) which is 9.2 statute miles.

Aside from the takeoff and landing activities at the Peekskill Seaplane Base, only one airway and two direct routes occupy airspace within 2 miles of Indian Point. The traffic carried by these routes on the historical peak day in 1977 is used for the purpose of calculating the probability of an aircraft hit.

The values of each input variable and the resulting hit probability of an aircraft using the stated airway are listed in Table 7.6-2. The total hit probability from airways traffic is

$$P = 4.6 \times 10^{-8}/\text{year}$$

7.6.3 CONCLUSIONS

Operations from the seaplane base and their potential consequences have been evaluated. In summary, for landing and take off operations, the annual probability of hitting the Unit 2 control building by a light aircraft is 2.4×10^{-7}. This calculation conservatively assumes the aircraft landings are adjacent to the plant when, in fact, most landings are made south of the plant and transmission lines, or in another direction away from the plant, since seaplane landings and takeoffs occur across the width of the river. Potential aircraft accidents from air traffic in designated airways and routes in the vicinity of the plant have also been evaluated. The annual probability of a large aircraft hitting critical plant buildings is approximately 4.6 x 10^{-8}. Therefore, the annual frequency of hitting a critical structure at Unit 2 is 2.9 x 10^{-7} and much less for Unit 3. The frequency of core melt from aircraft operations is less. In summary, accidents from aircraft using the airways in the vicinity of the plant, and all local airport operations, present no significant hazard to Indian Point.

7.6.4 REFERENCES

7.6-1 Schwartz, M., U.S. Corps of Engineers, New York District, personal communication to H. F. Perla, February 1981.

7.6-2 Reeves, K., Mahopac Airport, Mahopac, NY, personal communication to H. F. Perla, May 2, 1981.

7.6-3 Coopersmith, M., Ramapo Valley Airport, Spring Valley, NY, personal communication to H. F. Perla, February 17, 1981.

7.6-4 Martin, J., Airport Owner, Peekskill Seaplane Base, Verplanck, NY, personal communication to H. F. Perla, February 25, 1981.

7.6-5 U.S. Nuclear Regulatory Commission, Regulatory Guide 1.70, Revision 3, Section 3.5.1.6, November 24, 1975.

7.6-6 U.S. Nuclear Regulatory Commission, Standard Review Plan, NUREG 75/097, Section 3.5.1.6, November 24, 1975.

7.6-7 Sheth, P., et al. "Investigation of Effect of an Aircrash on the Containment Vessel at Indian Point No. 2," Franklin Institute Research Laboratories, 311-C3082-01, September 1971.

TABLE 7.6-1

NUMBER OF FLIGHTS ON AIRWAYS WITHIN TWELVE MILES OF INDIAN POINT

(Peak Day, 1977)

Airways	Distance from Plant in Miles	Number of Flights Per Day
Designated Airways:		
J37	8-1/2	11
V157	2	6
V34	12	65
V292	9	0
V3	11	89
Direct Route Airways:		
HUO 128	5 1/2	37
7JP-JFK (J37)	8 1/2	64
HUO-CMK	5	2
HNK-CMK (V34)	12	2

TABLE 7.6-2

AIRWAYS TRAFFIC HIT PROBABILITIES

Airway or Route	Distance, Centerline of Airway to Plant, Miles	Annual Number of Flights, N	Width of Hit Region, W, Miles	Probability, P, of a Hit Into Plant
V157	2	2,190	9.2	7.1×10^{-9}
HUD 128	5-1/2	13,505	11.0	3.7×10^{-8}
HUD-CMK	5	730	10.0	2.2×10^{-9}
TOTAL				4.6×10^{-8}/year

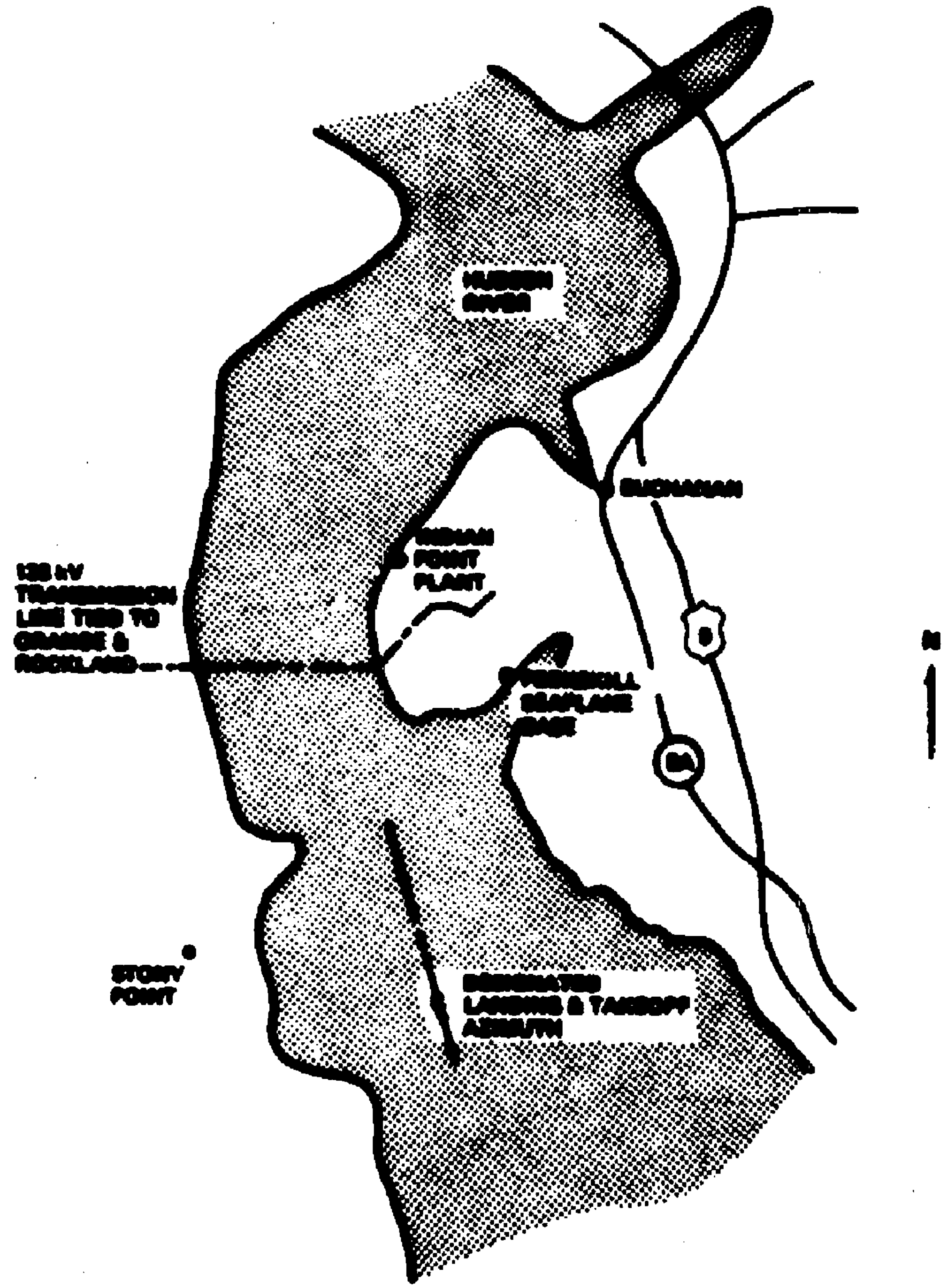

Figure 7.6-1. Peekskill Seaplane Base

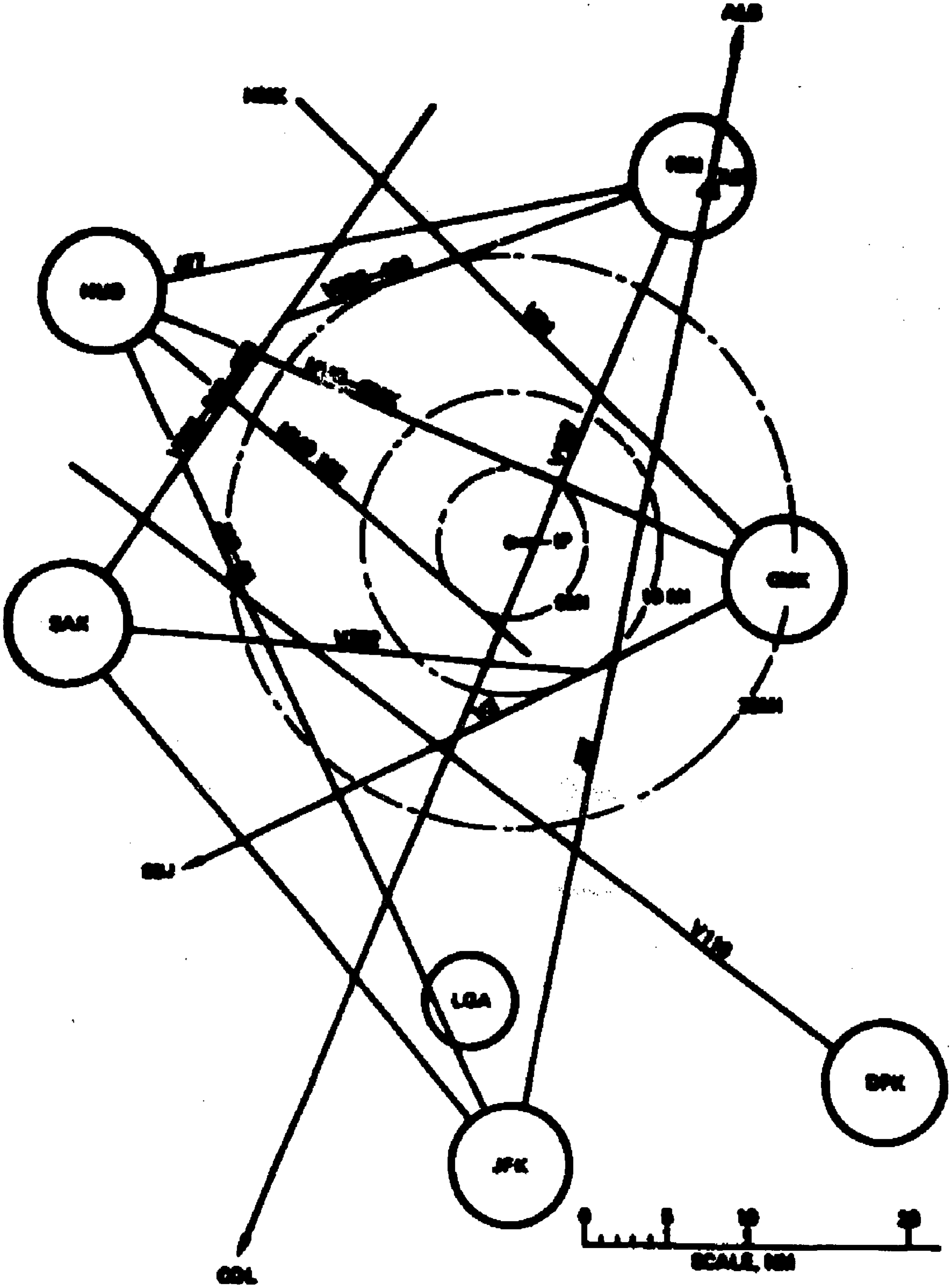

Figure 7.6-2. Airways in Vicinity of Indian Point

7.7 TRANSPORTATION AND STORAGE OF HAZARDOUS MATERIALS

This section describes the assessment of the probability of core melt at Indian Point resulting from offsite and onsite incidents involving transportation facilities and hazardous materials. Nearby transportation facilities and routes are examined as are proximate concentrations of hazardous materials of significance. The transportation facilities considered include rail, road, and shipping traffic. Aircraft traffic was considered in the previous section of this report.

7.7.1 RAIL TRANSPORTATION

The nearest rail facilities are located about 0.9 miles west and 0.6 miles east of the plant site. These CONRAIL lines carry freight, including a variety of hazardous chemicals. Chemicals having more than 30 shipments per year are required by Regulatory Guide 1.78 to be analyzed and are listed in Table 7.7-1. In addition to fuel oil, hazardous materials reportedly transported on the lines include chlorine, hydrochloric acid, sodium hydroxide, sulfuric acid, and phosphoric acid (Reference 7.7-1). There are no rail spurs on the site so none of these materials is shipped onsite by rail.

7.7.2 ROAD TRANSPORTATION

The nearest major road is New York Highway 9 extending north/south and located about 2 miles east of the plant site. Interstate highways I-684 and I-87 serve to relieve industrial traffic from Highway 9. Highway 9 carries truck traffic which may, on occasion, transport hazardous materials. For example, it is estimated that approximately 2 million gallons per year of liquid propane gas is transported by truck on this route. Onsite truck traffic is limited to the delivery of hydrogen, sodium hydroxide, sulfuric acid, diesel and gas turbine fuel oil, and minor quantities of ammonium hydroxide and hydrazine (Reference 7.7-1). The probability of core melt from incidents involving such deliveries is judged to be extremely small because of: (1) the controlled nature of onsite traffic, (2) the limited volumes delivered, and (3) the frequencies of such deliveries. The distances to major highway traffic also support this same conclusion.

7.7.3 BARGE AND SHIP TRAFFIC

Barge shipments to the Indian Point plant average three deliveries per year of about 3 million gallons of number 6 oil for house service boilers and one delivery of sodium hydroxide. The fuel barge capacity is 20,000 barrels. The river traffic is comprised of about 15,000 vessels in each direction each year (Reference 7.7-2). The maximum vessel draft permitted is 32 feet. Consequently, most of these vessels are tugs that direct barges and other low draft vessels. There are also numerous pleasure and passenger craft. The remaining traffic includes chemicals, grain, and other products which are transported to points between New York Harbor and Albany. Within this general category, about 600 tankers and 2,600 barges that carry petroleum products pass the plant on an annual basis. An accident involving passing barges might be postulated, from which there could be a fire at the shoreline or a release of sodium hydroxide.

A study to assess the probability of liquid natural gas spills in Boston Harbor (Reference 7.7-3) included examination of the frequency of accidents and spills involving vessels carrying the lighter petroleum fractions in well traveled areas as well as examination of the frequency of large, rapid spills (2,000 tons at a rate of 600 tons per minute or more) which could cause large fires or explosions. Some analogies can be drawn from that study to provide a conservative estimate of the probability of a fire adjacent to the Indian Point site caused by the collision of vessels in the Hudson River. Data in the Boston Harbor study were obtained from sources including the U.S. Coast Guard and the Oceanographic Institute of Washington State. The study concluded that the annual probability of large, rapid petroleum spills in Boston Harbor was between 2.0×10^{-6} and 2.0×10^{-5} per year. This was based on U.S. and worldwide data which indicated that the probability of collision casualties per harbor visit range from 2.0×10^{-4} to 5.0×10^{-3}. Generally, less than half of the reported accidents result in a spill of any significant size, let alone a large, rapid spill. The probability of a large, rapid spill was estimated to be between 3.0×10^{-6} and 3.0×10^{-9} per vessel visit. Their data involved vessels with minimum drafts of from 7 to 23 feet and minimum weights of from 180 to 7,000 dead weight tons, respectively. The probability of a spill in Boston Harbor was based on a distribution of collision data for vessels of these various sizes.

Factors which affect the consequences of accidents and spills include the size and distribution of storage tanks per vessel (although penetration of more than one or two tanks of up to 5,000 DWT each has seldom been experienced), the speed and size of the striking vessels, the penetration of the storage tanks in a collision, and the amount of traffic in the area. Of 28,000 vessels passing the plant annually, only 3,200 carry petroleum products. Thus, given a collision between any two vessels, only about 1 in 10 would involve a vessel carrying petroleum products.

The transport route comprises about 200 miles of the river and it can be estimated that a collision within a mile of the plant could spill significant quantities of petroleum products that might be capable of a significant burn at the shoreline. Therefore, given a spill in the river, there is a 1:200 chance it will be in the vicinity of Indian Point. In fact, however, a spill is much more likely to occur at or near loading facilities where the traffic will congregate, and, therefore, a 1:1,000 chance of a spill near Indian Point is a better estimate.

Using the data from the Boston Harbor study and the data on the transport of petroleum products along the Hudson River, the probability of an accident resulting in a rapid spill in the vicinity of the Indian Point site is approximately

$$(3.0 \times 10^{-6} \text{ to } 3.0 \times 10^{-9}) \times 28{,}000 \times \frac{1}{10} \times \frac{1}{1{,}000}$$

$$= 8.4 \times 10^{-6} \text{ to } 8.4 \times 10^{-9}$$

The continuous river traffic is different from and safer than the harbor traffic because the latter is more confined and involves more maneuvering. Therefore, collision probabilities should be further reduced. Considering the requirement for the spill to remain sufficiently concentrated at the shoreline to support combustion and the requirement that there be an ignition, we can assign an annual frequency of fire occurring at the shoreline of about 1.0×10^{-7} to 1.0×10^{-9}. A fire at that location would not affect any equipment that would preclude a safe shutdown and, therefore, the probability of a core melt from a river accident is extremely small.

7.7.4 GAS TRANSMISSION LINES

There are two natural gas transmission lines passing through the Indian Point site about 400 feet from the nearest Unit 3 plant structure and about 1,000 feet from the Unit 2 plant structures. Both gaslines, one 26-inch and the other 30-inch OD, were successfully hydrostatically tested after installation in 1952 and 1965, respectively, to at least 92% of yield stress (Reference 7.7-4). Since then, the Algonquin Gas Transmission Company has retested similar sections of 26-inch line with no adverse results. The trenches in which the carbon steel pipelines are buried were excavated in rock to about 3 feet and, therefore, are not expected to settle and cause failure. Each line contains a pressure relief valve at some distance from the plant, set at 750 psi which is less than 70% of the pipe's yield stress. The lines are now operated at a maximum of 650 psi. An automatic shutoff valve is located at the east side crossing of the Hudson River and in Yorktown, New York, some 10 miles away. Both lines are coated and are cathodically protected.

A review of the most recent "Annual Report on Pipeline Safety" published by the U.S. Department of Transportation (for calendar year 1979) was accomplished to determine the failure frequency of large gas transmission pipelines. The following pertinent statistics were taken from the reference.

1. About 70% of all failures result from damage by outside forces and about 30% occur due to corrosion, construction defects and material failures. Because the pipe is buried, well marked and not in a construction zone, only 30% of the failures are assumed to apply to the Algonquin pipelines.

2. There are about 280,000 miles of transmission pipelines similar to those near the site currently in operation in the United States.

3. Approximately 500 transmission and gathering pipeline accidents occur annually. Because gathering represents about 25,000 miles, it is assumed that about 450 of the accidents are associated with transmission pipelines.

4. The Algonquin Gas Transmission Company reports (Reference 7.7-4) that in 20 years there has been only 1 large leak and 13 small leaks reported. Therefore, it is assumed that about 7% of the accidents involve large leaks. This assumption may be high by a factor of 10.

To determine the probability of a large pipeline failure at the site using the above statistics, it was postulated that a hazard exists along a 1/2 mile section of the pipeline adjacent to the plant. Because there are two pipelines, the assumption involves a total of 1 mile of pipe. Only a large failure resulting in a large leak and fire is considered because smaller leaks would not jeopardize the plant. Examination of meteorological data indicates that the probability of wind blowing from the pipeline toward the plant (i.e., winds from the south/southeast) is 0.14.

There is an extensive preventive maintenance program associated with the Algonquin pipeline (Reference 7.7-4). For example, an aerial survey is performed twice a week over the entire pipeline to identify dead vegetation (indicative of gas leaks and fire hazards), construction in the vicinity, tree cutting activities, etc. A foot patrol is performed over the entire line twice a year using leak survey equipment. In addition, a monthly vehicle patrol inspects the pipeline near vehicle access points, and the cathodic protection system is inspected weekly. These inspections have been performed on the lines regularly for many years. Such inspections will preclude small leaks from growing to large leaks or ruptures through a lack of detection. On this basis, the probability of a large leak or rupture going undetected was estimated to be 1.0×10^{-1}.

The relationship used to determine failure probability is

$$P_{Lf} = N_f D f_s f_w f_t f_d / L$$

where

P_{Lf} = annual probability of a large pipeline failure near the plant

N_f = number of transmission line failures per year in the United States

L = miles of transmission pipeline in the United States

D = distance of pipe near site (miles)

f_s = fraction of failures that are large

f_w = fraction of time wind will blow toward plant from pipeline

f_t = fraction of failures due to construction related failures and corrosion

f_d = fraction of leaks going undetected

$$P_{\ell f} = 450 \times 1.0 \times 0.07 \times 0.14 \times 0.3 \times 0.1/280{,}000 = 4.5 \times 10^{-7}\ yr^{-1}$$

If a large leak occurred, the automatic shutoff valves would close with the drop in pressure and isolate the 10-mile section of the line passing the plant. In a controlled blowdown of the line, the gas empties out in a little over an hour. With a line break, it is estimated that gas would flow out and support combustion for a total of 15 to 20 minutes. Even with a large leak, there is still a possibility that it would not ignite. Nonetheless, if a fire occurred and threatened the plant, perhaps even destroying the offsite power supply transmission lines, the plant could be shut down using unit diesel generator or gas turbine power. This could be done before an initiating event could occur or before damaging a sufficient number of components in the safeguards systems, thereby precluding safe shutdown.

A study by United Engineers and Constructors (Reference 7.7-5) investigated the consequence of a gasline explosion at the site and cited the results of the 1965 Natchitoches, Louisiana, pipeline explosion whereby pipe missiles were found as far as 351 feet from the point of the blowout. Such missiles would pose little threat to the Unit 3 facilities which are 400 feet or farther from the gasline, or to the Unit 2 facilities which might be more vulnerable, but which are located 1,000 feet from the line and which are protected by a number of other structures.

In view of the foregoing, we can assign an annual frequency of 5.0×10^{-7} for a gasline fire which threatens the plant and the probability of its leading to a core melt is extremely small.

7.7.5 STATIONARY SOURCES OF HAZARDOUS MATERIALS

Table 7.7-2 lists the types and quantities of chemicals stored at the plant and their general locations (References 7.7-1 and 7.7-6). Fuel oil is also stored onsite. However, it poses essentially no explosive hazard in countless civilian and military applications. Further, the fire hazard from this fuel is drastically reduced by the physical storage arrangements. The station does not store or use chlorine as a gaseous or liquid product.

The chemicals listed (Table 7.7-2) are stored in pressure vessels or controlled containers and are isolated or otherwise protected from direct access to the control rooms or other critical facilities. Gaseous exhaust from postulated leaks in these onsite containers is not hazardous except in the immediate proximity of the leak. Explosive energies of stored gases are protected from critical facilities by separation distances and intervening structures.

The stationary sources of potentially toxic materials offsite and within 5 miles of the plant were identified in Reference 7.7-1. These are discussed further.

7.7.6 ANALYSIS OF HAZARDS EFFECTS

Reference 7.7-1 identifies the chemicals which require further analysis. Others were eliminated because they are infrequently shipped, are stored in insufficient quantities so that they are not considered hazardous, or because they do not have physical properties that enable them to become a toxic gas. A summary of the remaining chemicals (mobile and stationary sources) is presented in Table 7.7-3. Analysis is in progress to determine the potential toxic effects from these chemicals. The result will be that if potential effects are significant enough to be of concern, corrective actions will be taken to reduce the hazard or effects to acceptable levels. On that basis and on the basis of the foregoing evaluations, we conclude that the effects from hazardous materials leading to core melt are extremely small.

7.7.7 REFERENCES

7.7-1 Consolidated Edison Company of New York, Inc., letter to NRC from John O'Toole, Enclosure 2, dated May 12, 1981.

7.7-2 Schwartz, M., U.S. Corps of Engineers, New York District, personal communication to M. F. Perla, February 1981.

7.7-3 Lave, L., and M. Kazarians, Probability of LNG Spills in Boston Harbor - A Comparison with Conventional Tanker Spills, UCLA-ENG-7866, December 1978.

7.7-4 Lawson, E., Algonquin Gas Transmission Company, Boston, MA, personal communication to M. F. Perla, February 1981.

7.7-5 United Engineers & Constructors, Inc., Plant Capability to Withstand an Explosion and Fire in a Gas Transmission Line For Indian Point Generating Station, Unit 3, April 1968.

7.7-6 Consolidated Edison Company of New York, Inc., letter to NRC from Peter Zarakas, July 1, 1980.

TABLE 7.7-1

<u>OFFSITE RAIL/BARGE TRANSPORTATION OF HAZARDOUS CHEMICALS</u>

Chemical	Distance From Plant (miles)	Shipments/Year	Average Shipment Quantity (tons)
Anhydrous Ammonia	0.9	48	64
Carbolic Acid	0.9	214	87
Carbon Dioxide	0.9	89	81
Chlorine	0.9	213	77
Chlorine	0.6	31	50
Denatured Alcohol	0.9	121	68
Ethyl Acetate	0.9	34	75
Formaldehyde Solution	0.9	45	91
Hydrochloric Acid	0.9	127	89
Methanol	0.9	279	84
Petroleum Naphtha	0.9	84	64
Phosphoric Acid	0.9	67	90
Sodium Hydroxide	0.2	80	150
Sulphuric Acid	0.9	70	76
Xylene	0.9	30	45

TABLE 7.7-2

CHEMICAL STORAGE AT INDIAN POINT

Chemical	Quantity	Location at Plant
Carbon Dioxide (liquid)	64,000 SCF	Unit 1 -- Service Water Pumps Area
Hydrogen	23,300 CF @ 1500 psi	Unit 1 -- Service Water Pumps Area
	23,300 CF @ 1500 psi	Unit 1 -- Chemical Systems Bldg Area
	263 CF @ 1500 psi	Unit 2 -- PAB
Ammonia Hydroxide	55 gallons	Unit 2 -- Turbine Building
Hydrazine	220 gallons	Unit 2 -- Turbine Building
	165 gallons	Unit 3 -- Turbine Building
Sodium Hydroxide	6,000 gallons	Unit 3 -- Service Boiler Building
	9,700 gallons	Unit 1 -- Nuclear Service Building
	4,200 gallons	Unit 3 -- PAB
Sulfuric Acid	500 gallons	Unit 2 -- Turbine Building
	6,000 gallons	Unit 3 -- Service Boiler Building
	500 gallons	Unit 3 -- Turbine Building

Sources: References 7.7-1 and 7.7-6

TABLE 7.7-3

TOXIC CHEMICALS HAZARDS TO BE ANALYZED

Chemical	Quantity Offsite (gallons)	Tons Transported/ Vehicle (avg)	Distance To Control Room (mi)
Anhydrous Ammonia	-	64	0.9
Benzene	12,400	-	3.8
Carbon Dioxide	-	81	0.9
Chlorine	-	77	0.9
Chlorine	-	50	0.6
Denatured Alcohol	-	68	0.9
Ethyl Acetate	-	75	0.9
Ethylene Dichloride	7,410	-	3.8
Hydrochloric Acid	-	89	0.9
Hydrogen Cyanide	11,000	-	3.8
Methanol	-	84	0.9
Toluene	7,000	-	1.5
Trichloroethane	95,905	-	3.8
Xylene	-	45	0.9

7.8 TURBINE MISSILES

Turbine blades in turbine-generators could fracture and fragments could be ejected at high velocities, breaking through the turbine casing. These missiles could affect safe operation. The missile analyses which were performed for the FSAR were based upon a comprehensive study of turbine failures performed by Bush of Battelle Pacific Northwest Laboratories (Reference 7.8-1). Experience at that time indicated that the probability of a missile being ejected from the casing would be about 1.0×10^{-4} per year. This probability for missile ejection was used in the analyses.

Currently, utilities are reanalyzing their units for potential turbine missile ejection and hits on vital equipment, based on turbine failure studies in progress by Westinghouse Corporation. In those studies, the failure mechanism has been assumed to be fatigue cracking. Recent inspections of low pressure rotors revealed the presence of stress corrosion cracking in the keyway and bore areas. This cracking mechanism is being incorporated into the calculations for the probability of a missile exiting the turbine shell. Preliminary analyses indicate that, given a frequent inspection interval for the low pressure rotors, the annual frequency of missile ejection is below 1.0×10^{-4}.

This frequency (i.e., 1.0×10^{-4} or less per year) combined with the plant specific probabilities of the missile hitting safety related equipment results in a total hit frequency of 1.0×10^{-7} or less. The earlier models used in the FSAR for calculating the probability of a missile exiting the turbine casing may be revised to incorporate the stress corrosion phenomena when the Westinghouse studies are completed.

7.8.1 REFERENCES

7.8-1 Bush, S. H., "Probability of Damage to Nuclear Components Due to Turbine Failure," Nuclear Safety, Vol. 14, No. 3, 1973.

7.9.1 DAMES & MOORE SEISMICITY STUDY

Exhibit F

Exhibit F

UNITED STATES
NUCLEAR REGULATORY COMMISSION

In the matter of

ENTERGY NUCLEAR INDIAN POINT 2 L.L.C.,	)	
ENTERGY NUCLEAR INDIAN POINT 3, L.L.C,	)	License No. DPR 26 and
And Entergy Nuclear Operations, Inc.	)	License No. DPR 64
and Entergy Northeast, Inc.,	)	
regarding the Indian Point Energy Center	)	Docket No. 50-247 and
Unit 2 and Unit 3License Amendment	)	Docket No. 50-286
Regarding Fire Protection Program	)	

DECLARATION OF ULRICH WITTE
REPLY TO RESPONSEs BY ENTERGY AND STAFF ANSWERING PETITION FOR LEAVE TO INTERVENE, REQUEST FOR HEARING, AND CONTENTIONS REGARDING LICENSE RENEWAL OF INDIAN POINT UNIT 3 AND UNIT 2

My name is Ulrich Witte. WestCAN, RCCA, PHASE, and the SIERRA CLUB, and Assemblyman Richard Brodsky have retained me as a consultant and Expert Witness 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 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 incomplete License Renewal Application submitted by the Applicant submitted after several attempts, and formally accepted for docketing by Staff, and published on August 1, 2008.

I note that the License Renewal Application was significantly amended again, on and submitted to the ASLB, Staff, and other parties, after an extensive 181 page amendment. It was not however, made placed in the Federal Register for public review. Change should have be noticed to all the intervening organizations, it also apparently was not.

My expertise in Configuration Management in the industry is particularly relevant to my judgment surrounding program fidelity, completeness, and compliance to federal rules. I have assisted seven plants during my tenure in reestablishing the foundational prerequisite licensing basis and design bases, together with the integration of complex programs after the Licensee lost the ability to operate in compliance with federal rules, such as 10CFR54(f), and often required more than a year to return to service. My curriculum vitae is provided in Attachment 1 to this declaration.

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."

License renewal is be "strict design" under the rules, and as held by current precedence in renewal proceedings, can be summarized into the following four narrow areas of scope:

The Staff's well as the Applicant's response to our petition and for that matter to all of the petitions submitted, is that by "strict design," License Renewal (as codified in 10CFR54 and 10CFR51) can be simplified to address four things—and four things only:

(a) Aging of the plant structures, systems, and components will be sufficiently managed – where one cannot argue they are already addressed within the current license basis.
(b) review of time limited aging evaluations

(c) environmental impact analysis that is clearly plant specific and not generic, (for example, severe accident risk is out of scope but alternatives to severe accidents are in scope)
(d) anything else that one can prove is only possible during the renewal period but not during the current license period.

This very narrow scope is misconstrued as a structural boundary of the renewal scope in its core basis. As asserted in both the Back Ground and Summary sections of this reply actual renewal can only be legally narrowed to this points if (1) the current license basis is known, and the applicant as available incontrovertible evidence that proves compliance, (2) the present programs to be relied upon are sound, and the record provides the public as well as the Commission confidence, that rationale for extended the license term beyond the engineered design life is both safe and environmental sound.

Example after example show otherwise. Indian point was design to *suggested* criteria by a lobbying organization. Neither plant was designed or constructed to even draft design criteria, and it shows. The LRA states otherwise. See for example page 7 of Unit 3 LRA.

The results are not insignificant. Feedwater pipe bucking on Unit 2, a Steam generator tube rupture on Unit 2, fire protection program breakdowns that are substantial, and currently unresolved. Even an emergency plan is not functional after decades of wrangling between the regulator, congressional leadership, community leadership, and decades is telling. On January 7, 2008, Entergy acknowledged the existence of a credible report (see Exhibit F), where contaminates are leaking into the Hudson river principally from two leaking spent fuel pools, but not limited to other sources as described in contentions within this petition. The Report appears to assume the Hudson river water is not currently potable, and not used for drinking. However, that condition is expected to change.

These issues all point to a broken Configuration Management Program. Under item, (d) above, there appears to be no plan to correct this and this is a clear example, of "any other issue anything else that one can prove is only possible during the renewal period but not during the current license period."

For the Applicant to claim "trust me" in response after response" where specifics are required, and ambiguities are provided is a duck and run tactic. In precedence that tolerated an approach of that essentially can be summarized as "we'll figure this out later when we get a grip." As an engineer, and expert in configuration management, one can only wonder how a problematic plant can argue the most fundamental violation of contract law as acceptable and sufficient. An agreement to agree to resolve the problem later is void. The issues where the Applicant does this are: Flow Accelerated Corrosion, (what constitutes precise scope, including inspection of buried biping), Equipment Qualification (what and when to replace components), and reactor vessel internals analysis required for TLAA. The applicant has failed miserable on this issue already at Vermont Yankee, and this presently a significant element to renewal at Entergy's sister plant. The known problem of High Head Safety Injection System design is a clear example of TLAA scope falling short, and yet the public and the regulator is being asked to "trust Entergy." In my 26 years in assisting plants recover from being shutdown for extended periods. Trust me. Was not in any one's vocabulary. Not the rule, not the guidance, and certainly not earned by past performance. Transparency was. The LRA is NOT transparent. The recent six violations on Unit 3 continue to support the breakdown in core configuration management a t Unit 3. The OIG report regarding license renewal reinforces the breakdown. Fire protection (in particular Hemyc wrap being installed in 1995 on Unit 3, known to be deficient within a few years. Yet was left as is, for eleven years—and is uniquely[1] pencil whipped into the condition by Entergy as not actually being a problem at. I beg to differ. The license is in current violation of the one hour rule with an unlawful "exemption" that is ungrounded and does not defend the risks to the public as acceptable. I cannot agree that the vague dates to manage the staggering number of issues with the facility back to safe operation and regulatory compliance in the future are sufficient to assert that Entergy will accomplish the core elements of renewal scope.

What is left for inference but not available for direct facial challenge is that the rule bypasses a plethora of issues that start from current unresolved problems

[1] With the exception of Entergy's James A FitizPatrick Plant which also received an exemption for a similar condition in 2006.

and are expected (by engineering rigor and not mere speculation) to either not be resolved at the end of the current license period, or more importantly, reflect a failed implementation of design criteria, operational criteria; or design basis accident mitigation that actually worsen by extending the operating license. Any topic that is addressed elsewhere is argued by Staff as out of scope—for example, emergency planning, or design basis threat. In the face of precedence that states otherwise, I believe this is fundamentally a failure by the Commission to accomplish its mandate. The physical and materiel scope of license renewal including specific plant systems, structures, components is incorrectly interpreted by the Staff—and significant areas of scope are improperly excluded.

The nexus between adequate engineering, design and operation, and maintenance of the existing plant is relevant to the predicted aging of safe operation of the extended facility. This challenge cannot be set aside – but instead must be resolved a priori to current renewal proceedings. (applicable law: precedence for this is some of this is in place from ASLB proceedings regarding VY)

First, the materiel condition of the plant matters and that depends heavily how the plant was designed, operated, modified, and maintained compliant. i.e. the efficacy of the physical plant through the past 45 years since construction needs to be provable by the docketed record including compliance to the historical and current license bases <u>by the applicant</u>. Second, the rules and case law by themselves establish the sufficiency of the license bases so as to adequately implement the congressional enacted statutes governing the protection of the health and safety of the public, as well as minimizing risk to the public assets.

The rules as codified in part 2, together with the case law are deliberate in reigning in the scope to the above four narrow areas, and it is left to the petitioner, (at least within the agency's forum for adjudication) to argue by inference the relevancy of the historical condition, accidents, design failures, insufficient corrective actions, incomplete modifications, and margin is adequate as a starting point to show that reactor, its control, and safety-related systems designed for forty years, may be safely operated for 60 years *with* substantial power up rates.

The nuclear regulatory commission's mandate is not being met by this narrow view. License Renewal proceedings as found in the hearings to date and the rules themselves, together demonstrate what is truly a stacked deck[2]. The Nuclear Regulatory Commission mandate itself is not currently implemented.[3]

In examining this contention for admissibility, we ask the Board independently ask it self the following with respect to this contention.

(1) Arguments for staying the renewal process—in spite of the Oyster creek

[2] See for example, United States Nuclear Regulatory Commission Staff Practice and Procedure Digest. Commission Appeal board and Licensing Board Decisions July 1972-January 31, 2004. Published 2005, known as NUREG-0386, Digest 13. 704 pages of mandated authoritative precedence regarding the rules provided under 10CFR2. Yet the digest contains a disclaimer that it is not necessarily correct, or complete, cautions the reader on the second page that precedent cited is current, and consistent with the new rules.

[3] See comments regarding the NRC's failure to implement is congressional mandate

precedence.

a. OIG report – the renewal process is broken.
b. Petition submitted supporting cessation of renewal proceedings until OIG renewal problems are corrected—specifically IP LRA as well as VY, Oyster Creek,
c. Vermont Governor and Vermont DPS calls for halt in renewal proceedings objection filed January 18, 2008.
d. The EPA calling for complete environmental assessment in October 2007.
e. Arguments that present new questions or contentions based upon new information (these could be submitted as a a new and distinct series of petitions)
f. December 18 changes to the LRA were material and substantial and unpublished.
g. Changes in security and confidentiality policy compels a conclusion that the LRA needs to be revised and to include areas formerly considered confidential and therefore beyond reach of public intervention. (see documents recently made public by the NRC)
h. OIG report regarding fire protection
i. Failure to incorporate DBT threat into the renewal process

(2) The physical and materiel scope of license renewal including specific plant systems, structures, components is incorrectly interpreted by the Staff—and significant areas of scope are improperly excluded. The nexus between adequate engineering, design and operation, and maintenance of the existing plant is relevant to the predicted aging of safe operation of the extended facility. This challenge cannot be set aside – but instead must be resolved a priori to current renewal proceedings. (applicable law: precedence for this is some of this is in place from ASLB proceedings regarding VY)

(3) NRC must compel the licensee to complete proper environmental impact assessments for 100's of significant changes to the facility need to be addressed. Applicable law: Environmental impact rulemaking (codification is currently in progress) to strengthen this acknowledged weakness of the rules.

I declare under the penalty of perjury that the foregoing is true and correct.

Executed this 15th day of February, 2008.

Ulrich K. Witte

State of New York)
)ss.:
County of Rockland)

SUSAN HILLARY SHAPIRO
Notary Public - State of New York
No. 02SH6060466
Qualified in Rockland County
My Commission Expires June 25, 20 11

On the 15th day of Feb., in the year 2008 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.

____
Notary Public

Exhibit G

Exhibit H

Exhibit "H"

7590-01-P

NUCLEAR REGULATORY COMMISSION

Proposed License Renewal Interim Staff Guidance LR-ISG-2006-02:

Staff Guidance on Acceptance Review for Environmental Reports

Associated with License Renewal Applications

Solicitation of Public Comment

AGENCY: U.S. Nuclear Regulatory Commission (NRC)

ACTION: Solicitation of public comment

SUMMARY: The NRC is soliciting public comment on its Proposed License Renewal Interim Staff Guidance LR-ISG-2006-02 (LR-ISG) on the acceptance review criteria for environmental reports (ER) provided by applicants for reactor license renewal. This LR-ISG summarizes the Title 10 of the *Code of Federal Regulations* Part 51 (10 CFR Part 51) requirements for ERs submitted with license renewal applications (LRAs), and provides a checklist that will be used by the NRC staff to verify the completeness of these reports prior to docketing. The NRC staff issues LR-ISGs to facilitate timely implementation of the license renewal rule and to review activities associated with an LRA. Upon receiving public comments, the NRC staff will evaluate the comments and make a determination to incorporate the comments, as appropriate. Once the NRC staff completes the LR-ISG, it will issue the LR-ISG for NRC and industry use. The NRC staff will also incorporate the approved LR-ISG into the next revision of the license renewal guidance documents.

DATES: Comments may be submitted by (insert date 60 days after publication in the *Federal Register*). Comments received after this date will be considered, if it is practical to do so, but the Commission is able to ensure consideration only for comments received on or before this date.

ADDRESSES: Comments may be submitted to: Chief, Rules and Directives Branch, Office of Administration, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001. Comments should be delivered to: 11545 Rockville Pike, Rockville Maryland, Room T-6D59, between 7:30 a.m. and 4:15 p.m. on Federal workdays. Persons may also provide comments via e-mail at rgs@nrc.gov. The NRC maintains an Agencywide Documents Access and Management System (ADAMS), which provides text and image files of NRC's public documents. These documents may be accessed through the NRC's Public Electronic Reading Room on the Internet at http://www.nrc.gov/reading-rm/adams.html. Persons who do not have access to ADAMS or who encounter problems in accessing the documents located in ADAMS should contact NRC Public Document Room (PDR) reference staff at 1-800-397-4209, 301-415-4737, or by e-mail at pdr@nrc.gov.

FOR FURTHER INFORMATION CONTACT: Ms. Jennifer A. Davis, Project Manager, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Washington DC 20555-0001; telephone 301-415-3835 or by e-mail at jxd10@nrc.gov.

SUPPLEMENTARY INFORMATION: Attachment 1 to this *Federal Register* notice, entitled *Staff Position and Rationale for the Proposed License Renewal Interim Staff Guidance LR-ISG-2006-02: Staff Guidance on Acceptance Review for Environmental Reports Associated with License Renewal Applications*, contains the NRC staff's rationale for publishing the proposed LR-ISG-2006-02. Attachment 2 to this *Federal Register* notice, entitled *Proposed License Renewal Interim Staff Guidance LR-ISG-2006-02: Staff Guidance on Acceptance Review for Environmental Reports Associated with License Renewal Applications,* identifies the guidance for reviewing ERs received with LRAs.

The NRC staff is issuing this notice to solicit public comments on the proposed LR-ISG-2006-02. After the NRC staff considers any public comments, it will make a determination regarding issuance of the proposed LR-ISG.

Dated at Rockville, Maryland this 8th day of February, 2007.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Pao-Tsin Kuo, Acting Director
Division of License Renewal
Office of Nuclear Reactor Regulation

STAFF POSITION AND RATIONALE FOR THE

PROPOSED LICENSE RENEWAL INTERIM STAFF GUIDANCE LR-ISG-2006-02:

STAFF GUIDANCE ON ACCEPTANCE REVIEW FOR ENVIRONMENTAL REPORTS

ASSOCIATED WITH LICENSE RENEWAL APPLICATIONS

STAFF POSITION:

The NRC staff intends to use a checklist of acceptance criteria when evaluating environmental reports submitted with license renewal applications. This guidance summarizes the 10 CFR Part 51 requirements for environmental reports submitted with license renewal applications, and provides a checklist that documents the review process used by NRC staff to verify the completeness of these reports.

RATIONALE:

The NRC developed a checklist of the requirements in 10 CFR Part 51 to document the NRC staff's acceptance review standards regarding the information that needs to be included in an environmental report. The staff finds that the utilization of the guidance provided in the checklist will facilitate consistency and efficiency in the NRC staff's acceptance reviews of environmental reports submitted with license renewal applications.

PROPOSED LICENSE RENEWAL INTERIM STAFF GUIDANCE LR-ISG-2006-02:

STAFF GUIDANCE ON ACCEPTANCE REVIEW FOR ENVIRONMENTAL REPORTS

ASSOCIATED WITH LICENSE RENEWAL APPLICATIONS

Introduction

Each applicant for renewal of a license to operate a nuclear power plant is required to submit with its application a separate environmental report (ER) in accordance with Title 10 of the *Code of Federal Regulations* (10 CFR 54.23). As stated in 10 CFR 54.23, the ER must comply with the requirements of Subpart A of 10 CFR Part 51. The requirements governing the contents of an ER submitted at the operating license renewal stage are specified in 10 CFR 51.45 and 10 CFR 51.53(c). This LR-ISG is being proposed to document the staff's practice in performing an acceptance review of ERs submitted as part of a license renewal application.

Background and Discussion

The NRC staff routinely reviews ERs against the requirements of 10 CFR 51.45 and 10 CFR 51.53(c) as part of the acceptance review of reactor license renewal applications. Staff review guidance governing reactor license renewal environmental reviews and the preparation of environmental impact statements is provided in NUREG-1555, *Standard Review Plans for Environmental Reviews for Nuclear Power Plants, Supplement 1: Operating License Renewal.*

Attachment 2

In conducting its acceptance review, the staff also relies on the guidance provided to applicants in Regulatory Guide 4.2, Supplement 1, *Preparation of Supplemental Environmental Reports for Applications to Renew Nuclear Power Plant Operating Licenses.* The regulatory guide provides methods acceptable to the staff for implementing the provisions of 10 CFR 51.45 and 10 CFR 51.53(c). While conformance with the suggested format of the regulatory guide is not required, use of the guide is expected to ensure the completeness of the information provided, assist the NRC staff and others in locating information, and result in more efficient and timely NRC staff review.

Proposed Action

The acceptance review checklist for ERs submitted with license renewal applications, available via ADAMS at Accession No. ML063190452, will be incorporated into the next revision of NUREG-1555, Supplement 1. The acceptance checklist is intended to be a tool to ensure efficiency and consistency in the staff's acceptance reviews and ensure that all necessary components of license renewal stage ERs are submitted in accordance with governing regulations. As noted in the checklist instructions, the absence of any of the information recommended in Regulatory Guide 4.2, Supplement 1, would not require that supplemental information be provided prior to acceptance of an application; however, applicants should expect that the absence of such information may result in more intensive environmental audit activities and/or issuance of early requests for additional information to support the staff's review. The docketing and subsequent finding of a timely and sufficient application (including the ER) does not preclude NRC reviewers from requesting additional information as a review proceeds, nor does it predict the NRC's final determination regarding the approval or denial of a license renewal application. This proposed LR-ISG is not intended to substitute or re-interpret requirements outlined in 10 CFR 51.45 and 10 CFR 51.53(c). The checklist is also expected to serve as a knowledge management tool for NRC staff members by specifying review criteria in a simplified, user-friendly format.

NUCLEAR ENERGY INSTITUTE

Project No. 690

cc:

Mr. Joe Bartell
U.S. Department of Energy
NE-42
Washington, DC 20585

Ms. Christine S. Salembier, Commissioner
State Liaison Officer
Department of Public Service
112 State St., Drawer 20
Montipelier, VT 05620-2601

Mr. James Ross
Nuclear Energy Institute
1776 I St., N.W., Suite 400
Washington, DC 20006-3708

Mr. Frederick W. Polaski
Manager License Renewal
Exelon Corporation
200 Exelon Way
Kennett Square, PA 19348

Peter A. Mazzaferro
Site Project Manager - License Renewal
Nine Mile Point Nuclear Station, LLC
P.O. Box 63
Lycoming, NY 13093

Mr. David Lochbaum
Union of Concerned Scientists
1707 H St., NW, Suite 600
Washington, DC 20006-3919

Mark Ackerman
Project Manager, License Renewal
FirstEnergy Nuclear Operating Company
P.O. Box 4
Route 168 (Mail Stop BV-SGRP)
Shippingport, PA 15077

Mr. Paul Gunter, Director
Reactor Watchdog Project
Nuclear Information & Resource Service
6930 Carroll Avenue, Suite 340
Takoma Park, MD 20912

Mr. Hugh Jackson
Public Citizen's Critical Mass Energy &
Environment Program
215 Pennsylvania Ave., SE
Washington, DC 20003

Mary Olson
Nuclear Information & Resource Service
Southeast Office
P.O. Box 7586
Asheville, NC 28802

Talmage B. Clements
Manager - License Renewal
Progress Energy
P.O. Box 1551
Raleigh, NC 27602

Mr. Garry G. Young
Manager, License Renewal Services
1448 SR 333, N-GSB-45
Russellville, AR 72802

Mr. William Crough, Manager
Licensing and Regulatory Affairs
Browns Ferry Nuclear Plant
Tennessee Valley Authority
P.O. Box 2000
Decatur, AL 35609

Patrick Burke
License Renewal Project Manager
Monticello Nuclear Generating Plant
Nuclear Management Company, LLC
2807 West County Road 75
Monticello, MN 55362-9637

Robert A. Vincent
Licensing Lead - License Renewal Project
Palisades Nuclear Plant
27780 Blue Star Memorial Highway
Covert, MI 49043

Exhibit M

Exhibit M

UNITED STATES
NUCLEAR REGULATORY COMMISSION

In the matter of

ENTERGY NUCLEAR INDIAN POINT 2 L.L.C.,	)	
ENTERGY NUCLEAR INDIAN POINT 3, L.L.C,	)	License No. DPR 26 and
And Entergy Nuclear Operations, Inc.	)	License No. DPR 64
and Entergy Northeast, Inc.,	)	
regarding the Indian Point Energy Center	)	Docket No. 50-247 and
Unit 2 and Unit 3License Amendment	)	Docket No. 50-286
Regarding Fire Protection Program	)	

SUPPLEMENTAL DECLARATION OF ULRICH WITTE REPLY ENTERGY'S RSEPONSE AND STAFF'S RESPONSE TO PETITION FOR LEAVE TO INTERVENE, REQUEST FOR HEARING, AND CONTENTIONS REGARDING LICENSE RENEWAL OF INDIAN POINT UNIT 3 AND UNIT 2 RE: CONTENTIONS 36

My name is Ulrich Witte. WestCAN, RCCA, PHASE, the Sierra Club—Atlantic Chapter, and Assemblyman Richard Brodsky have retained 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 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 Exhibit O.

I submit the following comments in support of each coalition stakeholder in Contention 36 regarding Entergy's Flow-Accelerated Corrosion Program for Indian Point Units 2 and 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

The need for Flow-accelerated Corrosion management:

Flow Accelerated Corrosion phenomena was outside original design basis analysis, and engineering analysis did not predict the catastrophic events of 1986 and the Surry Plant, where work workers were killed, when an 18 in pipe ruptured with no prior warning. The plant was 15 years old at the time of the event. Casual relation to actual safe operation of the plant and even potential loss of control room habitably was not foreseen, when steam condensate shorted circuit cards in fire control panels, dumping the entire CO2 system, rendering it inoperable and endangering additional human life. Since CO2 is heavier than air, concentrations eventually accumulated in the plant control room. Senior Reactor Operators elected to not evacuate the control room, and begin disoriented and in some case ill from oxygen displacement by the Carbon dioxide .

The issue at Indian Point is insufficiently managed now, as it is at other Entergy Plants.

Submitted with particularity and specificity are provided here in for Unit 2. Unit 3 contains a similar historical record. The records show that the issue exists for both plants. See Exhibit R.

In essence, the aging management program required for license extension is predicated upon a sound, compliant and complete design basis record. Use of CHECWORKS is predicated upon the plants material conditional being monitored under the auspices of the program and benchmarked against industry trends and both cite specific and events such as ruptured pipes or unpredicted pipe thinning at other facilities. Without this, the plant's material condition, basis design assumptions required for an adequate Flow-accelerated program cannot not be substantiated.

The issue of adequate benchmarking of data is part of the larger question that Contention 36 raises. To fully address the contention, the applicant needs to establish the proposed licensing basis for management of FAC vulnerability of plant piping, as required under NUREG 1801 for each relevant system; second, provide the technical ground for basis of a program that adequately assures the plant will be safely operated and maintained regarding FAC; and finally confirmation that the program developed is fully implemented, and durable for the extended operating period.

What the record shows is the following statement by Entergy: "The FAC program that will be implemented by Entergy during the license renewal period which is the *same program* being carried out today and will meet all regulatory requirements and industry guidance" . This sweeping statement contained in the current pending LPA, is vague, and provides no engineering insight. However, the identical program is implemented at Vermont Yankee by under the same procedures. With problems. After numerous independent evaluations the identical program was found to be admissible, and the ALSB in those proceedings found the material facts in dispute geninue, and ruled against a motion for summary disposition. The hearing is scheduled for this summer.

As the expert witness corroborating with another expert, in those procedures, and the statements made in the LRA my knowledge that the programs, procedures, and industry guidance is all identical, along with the record of pipe breaks of many can be characterized as likely FAC based such as exhibit R. I cannot conclude that aging management with respect to Flow Accelerated Corrosion Program at Indian Point meets the guidance of NUREG -1801, Section XI.M.17 nor the rule.

Industry experience, heightened attention, and new guidance reflect the need to narrow the uncertainties in predicting flow accelerated corrosion. The facts are that failures associated with FAC continue to occur. For example, during the past three years, pipe thinning or failure events have occurred at Duane Arnold, Hope Creek, Clinton, Braidwood, LaSalle, Peach Bottom, Palo Verde, Palisades, Catawba, Calvert Cliffs, Kawanee, Browns Ferry, ANO, and Salem. New failures currently being investigated for failure mechanisms include Cooper, SONGS, and Nine Mile point. Some of these plants have received power uprate approvals including stretch, and MU, and are operating at increased power levels, others have EPU applications in progress.

Of particular interest in those plants that have received UPE licenses, and their failure rates after baselining the configuration geometries and wear rates post UPE. A brief review includes Hatch (2005), Clinton, Palo Verde, Dresden, Quad Cities, Surry (2006 event), and Kewaunee. Each has seen a FAC related failure after EPU.

The facts clearly point to the uncertainty in predictability—and the danger of depending on one empirical program such as CHECWORKS as a free standing singular reliable tool to avoid negative margin or pipe failure is addressed within the guidance. Industry guidance suggests an overlapping approach. For example, under NUREG 1801, the VY LPA requires addressing numerous mechanical aging programs under GALL. The FAC program is one of them and needs to address each of the following elements:

(1) Scope

(2) Preventative actions

(3) Parameters monitored or inspected

(4) Detection of aging effects

(5) Trending

(6) Acceptance criteria

(7) Corrective actions

(8) Confirmation processes

(9) Administrative processes

(10) Operating experience

Included in items (3) and (4) and (5) is the need to establish parameters, trending, and detection of aging effects. No particular number is specified for benchmarking in the NUREG, however, a firm recommendation in the NUREG is that a comprehensive baseline be established. Given that each plant has unique characteristics and operating histories this is reasonable. Separate industry guidance supports 5-10 years of data trending. See for example, "Aging management and life extension in the US Nuclear Industry" October 2006, prepared by the Chockie Group International, page 38. The outer limit of this range supports my opinion of at least 10 years for Indian Point given the extent of mismanaged pipe and equipment leakage almost from day one, and the unlawful use of suggested original design criteria from a trade organization.

I am forced to conclude that Indian point Program for FAC remains unsubstantiated as acceptable for extended operation, and based on the facts does not assure protection of the health and safety of the public.

I declare under the penalty of perjury that the foregoing is true and correct.

Executed this 15th day of February, 2008.

UWitte

Ulrich K. Witte

State of New York)
)ss.:
County of Rockland)

On the 15th day of Feb., in the year 2008 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.

Notary Public

SUSAN HILLARY SHAPIRO
Notary Public - State of New York
No. 02SH6060466
Qualified in Rockland County
My Commission Expires June 25, 2008

Exhibit O

Exhibit "O"

Northern Lights Engineering, L.L.C.
71 Edgewood Way, Westville, Connecticut, 06515
Ulrich K. Witte

Ulrich K. Witte

Summary:

Over twenty-six year's of professional experience in engineering, configuration management, licensing, regulatory compliance of large scale commercial nuclear facilities. This includes management and implementation of design change control programs, engineering standards programs, multi-department/multi-functional licensing initiatives, plant design basis and engineering process improvement programs for six energy companies operating seven nuclear power plants. Responsibilities include:

- Systems solutions to plant operations, engineering modifications, safety analyses, design changes, installation and testing, software, drawing change programs, and training. Optimized function interfaces to insure proper coordination and synchronization for cost effective and compliant operation of the facility.
- Technical support management, and issue resolution programs that identified potential hardware, operational or equipment function issues, as well as document problems, data management problems and organizational enhancements
- Engineering Change Processes from change inception to document close-out
- Multi-department Configuration Management Program including technical approach, consensus, approval, and implementation. Managed a standing Configuration Management Programs Group whose goal was to integrate ten functional areas under a corporate strategic plan encompassing two nuclear facilities.
- Vertical slice system design/operation reviews, design bases / regulatory rule reconciliation, and licensing bases reconstitution and transitioning projects
- Integration of plant equipment information systems with business processes within engineering, materials management, maintenance, and plant operations.
- Structured business process modeling. Application of functional analysis purely from a data prospective—to enhance change management, efficiency.
- Chaired ANSI certified industry guidance on cost effective, compliant, and institutionalized programs for successful configuration management enhancement
- EPRI guidance on optimizing the Engineering Change Process
- Formal training to engineering department personal with specific courses on the engineering change process, plant safety analysis, and modification testing. Trained engineering personal on the requirements of the plant wide Configuration Management Program.

Office 203 389 4564
Mobil: 860 391 1183
Fax: 203 389 6657
Email: ulrich@ulrichwitte.com

Technical Consultant

Northern Lights Engineering, L.L.C., 71 Edgewood Way, Westville, Connecticut 06515 (May 2002 –Today)

Established a consulting practice where I provided expertise in matters affecting the safe operation and regulatory compliance of commercial nuclear power facilities. This includes licensing and regulatory compliance issues, modification and implementation of industry standards, engineering design reviews, and configuration management analysis associated with an unexpected event, a design failure, or an elevated risk condition, and includes review of proposed changes to the plant operating license in preserving design efficacy.

Technical Advisor and Expert Witness to IPSEC representing WestCAN, Clearwater, the Sierra Club - Atlantic Chapter, and PHASE
Providing technical advisory, expert witness work and legal assistance in preparing and submitting petition for leave to intervene and request for hearing with contentions regarding the license renewal application by Licensee for Indian Point Nuclear Units 2 and 3. This included preparing and filing an initial petition containing 51 contentions and several other petitions regarding fire protection for Unit 3, in context with the recent EPA letter, as well as Mothers v. NRC filed in 9th circuit, and the October 31 DEC/AG letter. The work includes, separate allegations of regulatory procedural violations regarding the Thermal Shock Proposed Rule, and recent Fire Protection Exemptions that appear to clearly violate to CFR Part 2, and the Design Basis Threat rule under 10CFR73. This effort includes expert review of the Aging Review Program, in particular flow-accelerated corrosion issues, and finite element fatigue analysis reviews of susceptible components and a number of other contentions related to the safe operation of each unit beyond its 40 year license.

Technical Advisor and Expert Witness to the law firm of Shems, Dunkiel, Kassel, & Saunders, PLLC
Currently providing technical assistance in pre-filed testimony regarding Entergy Nuclear Operations application for renewing the operating license of Vermont Yankee. This includes Aging Review Program, in particular flow-accelerated corrosion issues, and finite element fatigue analysis reviews of susceptible components and a number of other contentions related to the safe operation of the plant beyond its 40 year license at 120% of originally design power

Technical Advisor, to the law firm of Leroche, Meyers, and Conswel, LLP.
Provided licensing and regulatory compliance expertise in legal claim and derivative action by the board of directors of the First Energy Corporation against its corporate officers in their role associated with the Northeast black out of August 2003, and the mismanagement of the Davis Besse Nuclear Power Plant.

Technical Advisor to the Union of Concerned Scientists
Provided technical review of UCS analysis of the Davis Besse reactor head corrosion event. This included analysis of the loss of integrity of the reactor vessel, and the immediacy of the reactor head failure.

Senior Scientist, Dominion Resources Inc, Millstone Station:

P.O. Box 128, Waterford, Connecticut 06385-0128 (December 1996 – 2002)

Project Manager, Licensing Commitments. Established the Regulatory Commitment Management Program. Developed a program that established senior management and department level control of more than 30,000 licensing commitment that was previously broken. The substantially enhanced program captured, dispositioned, consolidated, and managed implementation of docketed commitments to the NRC. Status, responsibility and clear communication were successfully implemented to allow Millstone to successfully restart Units 2 and 3.

The effort required substantial procedure revisions, customer consensus building, and integration of separate free-standing department specific database applications, as well as the station wide action item tracking system. A near term deliverable necessary for the successful restart of Unit 3 was to provide a workable, compliant and functioning regulatory commitment management program.

Project Manager, 50.54(f) Licensing Bases Transition Project. I led a team of 14 individuals to disposition and validate approximately 5100 regulatory commitments necessary for restart of Unit 3. The effort has led to a quality rate of more than 98 percent with production average of about four hours per commitment.

Manager, Configuration Management Program, New York Power Authority:

123 Main Street, White Plains New York 10621, Nuclear Generation Department, Engineering Division
(November 1991 - November 1996)

Established the Configuration Management Program for the New York Power Authority's nuclear facilities. Included are 10 functional areas and integrated controls as authored in the corporate strategic plan. Management functions and technical skills include the following:

- Established Configuration Programs Group. This group and my position were established as a result of INPO Plant Evaluation calling for configuration management enhancement, and resolution of design control issues identified by the NRC in their DET Inspection of 1991 of the FitzPatrick Plant, as well as independent assessments. Recruited permanent staff, and supplemented the group with contracted staff on as needed basis to support both plants correcting significant technical and functional issues and being placed on the NRC's Watch List.

- Modified the engineering change process. Areas of immediate attention included the Design Control and Modification Programs, where a series of working groups were established to correct technical content and improve quality, ownership, and business efficiency of the design change process. This effort was achieved via: (1) a formal process to assess, model, and enhance the design change and modification process and interfaces to key functions; and (2) immediate changes to engineering procedures.

- Assessed and enhanced the Plant Equipment Data Base and controls for each plant. Results of the assessment indicated that the IP3 Plant Equipment Database contained significant problems with component classification, equipment type and status, maintenance history etc. Prepared and implemented a recovery plan and project team to reestablish the controls and content of database to be compliant with NRC Generic Letter 83-28 and to support the plant restart. Streamlined and enhanced the component classification process for both plants. Established controlled and non-controlled segregation of plant equipment in accordance with recent EPRI guidance.

- Automated and validated existing fragmented and corrupt sources of engineering information. These data sources were compiled, validated, and controlled and included multi-department areas such as set point controls, Electrical Cable and Raceway Information Systems for JAF and IP3, along with the fuse controls and data management.

- Developed design basis problem resolution process, "Design Document Open Item". Established methods for prioritizing, tracking and closing out design document issues. Established proper interface and control room notifications as per tech spec requirements. Provided guidance on operability determinations and reportability. Provided oversight for classifying and tracking more than 1100 open design issues for IP3 and 300 for JAF. Defended program to the NRC.
- Established working groups between Nuclear Generation Department and the corporate wide Information Management Organization. Gained management endorsement for areas of data quality improvement and automation for the Nuclear Generation Department. This led to enhanced implementation of the equipment information systems for both sites.

Project Manager, Program to Assure Completion and Quality, Tennessee Valley Authority:

(December 1990 - March 1991) Under contract by CYGNA Energy Services to the Vice-President, Engineering and Operations Department, Watts Bar Nuclear Plant.

- Developed a comprehensive plan to measure progress and confirm quality of the in-progress design evolution of the plant. Developed a methodology for linking specific plant equipment to that equipment's respective design basis (and associated design attributes); license commitments; and numerous verification programs currently in place. The five phase program was presented to NRR in January and received approval as an activity to assist TVA in removing the stop work order on construction of the facility.

Technical Manager, Configuration Management Program, Southern Nuclear Operating Company:

(December 1988 - November 1991). Under contract by ABB Impell and CYGNA Energy Services to Corporate Engineering Manager, Edwin I. Hatch Nuclear Plant, Georgia Power Company.

- Established and implemented the Hatch Configuration Management Program. Phase one of the effort included definition, establishment of management objectives, specification of the configuration management program scope and development of a reference manual.
- Developed and executed formal rigorous horizontal evaluations (the second phase of the project) of each relevant functional area including engineering design, implementation, plant operations and maintenance, procurement, information systems, document control and others. The program integrates functional areas across the plant, each architect engineer, and corporate (SONOPCO and Southern Company Services) organizations.
- Implemented enhancements to the program. This phase includes upgrading the design change process to achieve successful integration across organizations; stricter adherence to closure activities; and formal design engineering involvement in such activities as procurement of replacement items (equivalency). Additional controls were established such that misapplication of information obtained through informal design change processes such as the "Request for Engineering Assistance".
- Reconciling the plant's design basis. A second major activity of the program was to compile, consolidate, and ultimately, automate the plant's design basis. A major objective is to provide access and retrievability of current design basis to each of the key users of each participant organization.

- Applied Structured Business Analysis including CASE tools in the evaluation and enhancement phases. The as-found configuration management activities of all relevant processes were modeled and analyzed with this technique. Proposed enhancements are then tested on the model prior to actual implementation.
- Chaired the subcommittee for the Nuclear Information and Records Management Association which is developing a Technical Position Paper entitled, "Implementation of a Configuration Management Enhancement Program for a Nuclear Facility".

Team Leader, NRC Safety System Functional Inspection Response Organizations:

Led the NRC Safety System Functional Inspection Response Teams for Georgia Power Company (1989), and Sacramento Municipal Utility District (1987). Assisted as team coordinator in the GPC - Plant Hatch Electrical Distribution System Functional Inspection Response Team (1991). Under contract by ABB Impell (December 1987 - November 1990) to the site Engineering Manager, Rancho Seco, SMUD. and CYGNA Energy Services (December 1990 - November 1991) to the Corporate Engineering Manager, Edwin I. Hatch Nuclear Plant, Georgia Power Company.

- In the case of GPC, the NRC SSFI resulted in validation of the in progress implementation of the Hatch Configuration Management Program, and only one violation to the licensee.
- The effort included an SSFI self-assessment as well as managing the utility through the NRC inspection.
- For SMUD, developed and executed a plan for closure of both immediate findings and long term corrective action required. Assisted in defending the plan to the NRC.
- For GPC - Plant Hatch EDSFI in June 1991. Developed and implemented an EDSFI Preparation Plan for the Engineering (both A/Es) and site organizations. This effort included management of a 27 man team preparation and inspection response team for the Hatch EDSFI.

Deputy Mechanical Engineering Manager, Engineering Department

Under Contract to the Site Engineering Manager, Rancho Seco, Sacramento Municipal Utilities District, Rancho Seco (April 1986 - September 1987)

Managed the implementation and closure of over 400 modifications to the plant. Provided the NRC with a basis for allowing a successful restart of the facility. (January 1986 to November 1986) Impell Lead Project Engineer, Class 1 Piping and Support Recertification Effort, SMUD.

- Developed an engineering department action plan to improve technical quality, reconstitute design basis for five systems, control costs of plant modifications, and improve adherence to schedule.
- Responsible for the complete recertification of the Pressurizer Relief Line, Decay Heat System, and others. Responsible for expediting and implementing design changes as necessary through to closure. Assisted in Utility responses to NUREG-0737, and I&E 79-14.
- Upgraded the Engineering Department procedures to gain credit for the relaxation of ASME code requirements in structural damping values. Initiated the FSAR changes as well.

Project Engineer, Fire Protection:

Under Contract to Sacramento Municipal Utilities District, Rancho Seco (November 1984 to April 1986), SMUD Fire Protection Coordinator, Fire Protection Program

- Developed the SMUD Appendix R Fire Protection Program. Established or substantially revised 110 plant and engineering procedures including shutdown procedures on total loss of the plant's control room, technical specification surveillance procedures, fire protection system maintenance procedures, and the development of a fire protection program manual.

Successfully defended the program to the NRC during the 1985 Appendix R Inspection, with no resulting findings or open items.

Additional Experience (6/78 through 8/84):

Senior Engineer, performed original pipe stress analysis and support placement for Duke Power's Catawba Plant. Qualified approximately 8 class one and two plant systems. (ABB Impell 6/78 - 12/79).

Non-linear finite element analysis of large diameter piping for EPRI. Analysis of production stress codes versus non-linear evaluation techniques, versus actual in situ testing of the system. Results were published in EPRI Report "Seismic Piping Test and Analysis. (ABB Impell, 1980 -1981)

As Project Engineer, directed the preparation of the annual Emergency Plan exercises for Kansas Gas and Electric Company, Union Electric Company, and Texas Utilities. In two plants, the exercise was installed on the plants simulator, and received recognition from the NRC for realism of the scenario. (ABB Impell 1982-1984).

EMPLOYER SUMMARY:

Northern Lights Engineering, L.L.C. — 12/2002 – current
71 Edgewood Way
Westville, CT 06515

Northeast Utilities /Dominion Resources Inc — 12/1996 – 12/2002
(Under Contract via Cataract Inc through 9/97.)
2500 McClellan Ave.
Pennsauken, NJ 08109

New York Power Authority — 11/1992 -12/1996
123 Main Street
White Plains, New York 10671

Cygna Energy Services — 11/1991 - 11/1992
5600 Glenridge Drive, Suite 380
Atlanta, Georgia 30075

ABB Impell Corporation — 6/1978 - 11/1991
333 Research Court
Technology Park-Atlanta
Norcross, Georgia 30095

EDUCATION:

University of California, Berkeley
B.A. Physics, 1983
Senior level and graduate course work in Mechanical Engineering, and Electrical Engineering

Quinnipiac University School of Law
J.D expected June, 2009

PUBLICATIONS:

- EPRI Report Number 108736, "Guidelines for the Optimization of the Engineering Change Process," March 1994.
- NIRMA PP-03, "Position Paper for a Configuration Management Enhancement Program for a Nuclear Facility," April, 1992. Subcommittee Chair.
- EPRI Report Number 8480, " Seismic Piping Test and Analysis," 1980.

PROFESSIONAL AFFILIATIONS AND AWARDS

American Society of Mechanical Engineers, American Nuclear Society, Nuclear Information and Records Management Association, Who's Who For Rising Young Americans.

REFERENCES:

References available upon request.

Exhibit P

Entergy

Entergy Nuclear Northeast
Entergy Nuclear Operations, Inc.
Indian Point Energy Center
295 Broadway, Suite 1
P.O. Box 249
Buchanan, NY 10511-0249

September 1, 2005

Re: Indian Point Units No. 2 and 3
Docket Nos. 50-247 and 50-286
NL-05-094

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

SUBJECT: Response to NRC Generic Letter 2004-02, Potential Impact Of Debris Blockage On Emergency Recirculation During Design Basis Accidents At Pressurized-Water Reactors

References:
1. NRC Generic Letter 2004-02, "Potential Impact Of Debris Blockage On Emergency Recirculation During Design Basis Accidents At Pressurized-Water Reactors", dated September 13, 2004.
2. NL-05-023, "90-Day Response to NRC Generic Letter 2004-02, Potential Impact Of Debris Blockage On Emergency Recirculation During Design Basis Accidents At Pressurized-Water Reactors", dated February 28, 2005.

Dear Sir:

This letter provides Entergy Nuclear Operations (Entergy), Inc. response to NRC Generic Letter (GL) 2004-02 (Reference 1) for Indian Point Unit 2 and Indian Point Unit 3. The information requested by the Generic Letter is provided in Attachment 1.

Attachment 2 provides an update to commitments made by Entergy in the 90-Day response to the subject generic letter (Reference 2). No new commitments are being made in this submittal. If you have any questions or require additional information, please contact Mr. Patric W. Conroy, Licensing Manager at 914-734-6668.

I declare under penalty of perjury that the foregoing is true and correct. Executed on 9/1/2005.

Sincerely,

For,

Fred R. Dacimo
Site Vice President
Indian Point Energy Center

cc: next page

A116

Attachment 1: Indian Point Unit 2 and Unit 3 Response to NRC Generic Letter 2004-02
Attachment 2: Indian Point Unit 2 and Unit 3 Update to Commitments made in the 90-Day Response

cc:

Mr. John P. Boska, Senior Project Manager
Project Directorate I,
Division of Licensing Project Management
U.S. Nuclear Regulatory Commission

Regional Administrator
Region I
U.S. Nuclear Regulatory Commission

Resident Inspector's Office
Indian Point IP 2
U.S. Nuclear Regulatory Commission

Resident Inspector's Office
Indian Point IP 3
U.S. Nuclear Regulatory Commission

Mr. Paul Eddy
NYS Department of Public Service

INDIAN POINT UNIT 2 and UNIT 3

ATTACHMENT 1 TO NL-05-094

Response to NRC Generic Letter 2004-02, Potential Impact Of Debris Blockage On Emergency Recirculation During Design Basis Accidents At Pressurized-Water Reactors

ENTERGY NUCLEAR OPERATIONS, INC
INDIAN POINT NUCLEAR GENERATING UNITS 2 AND 3
DOCKETS 50-247 AND 50-286

Response to NRC Generic Letter 2004-02, Potential Impact Of Debris Blockage On Emergency Recirculation During Design Basis Accidents At Pressurized-Water Reactors

Addressees are requested to provide the following information no later than September 1, 2005:

Requested Information Item 2(a):

Confirmation that the ECCS and CSS recirculation functions under debris loading conditions are or will be in compliance with the regulatory requirements listed in the Applicable Regulatory Requirements section of this generic letter. This submittal should address the configuration of the plant that will exist once all modifications required for regulatory compliance have been made and this licensing basis has been updated to reflect the results of the analysis described above.

Entergy Response to Item 2(a):

The recirculation functions of the Emergency Core Cooling System (ECCS) and Containment Spray System (CSS) under debris loading conditions will be in compliance with the regulatory requirements listed in the Applicable Regulatory Requirements section of the subject generic letter in accordance with the new regulatory guidance. In order to ensure compliance, Entergy has performed and continues to perform analyses to determine the susceptibility of the ECCS and CSS recirculation functions to adverse effects of post-accident debris blockage and operation with debris-laden fluids. The analyses to date conform to the greatest extent practicable to the NEI 04-07 Guidance Report methodology (NEI GR)(Ref. 1) as supplemented by the NRC Safety Evaluation Report (NRC SER)(Ref. 2). (Refer to response to Item 2(c) for further information).

The following major activities have been completed:

- Containment walkdowns and surveillances with the exception of latent debris sampling for Unit 2
- Vendor debris generation analyses
- Vendor post-accident containment water level calculations

The following activities are currently in progress:

- Formal acceptance of completed vendor calculations
- Available Net Positive Suction Head (NPSH) analysis
- Entergy review of vendor debris transport analysis
- Entergy review of vendor downstream effects evaluations
- Development of conceptual design options
- Entergy review of vendor debris head loss evaluations (sump screen surface area determinations)
- Selection of the final design

- Selection of sump screen hardware vendor

The following activities are currently in planning:

- Assessment of margin to address chemical effects
- Programmatic and procedural changes
- Confirmatory latent debris sampling for Unit 2

Based on the work performed to date, modifications will be required to both the recirculation and containment sumps and associated screens. The Unit 3 Internal Recirculation (IR) pumps will be replaced to match the Unit 2 design in order to reduce the required net positive suction head. In addition, modifications may be required in order to reduce the amount of debris migrating to the sumps. These modifications may include the addition of flow channeling including flow diversion barriers/new crane wall openings, debris interceptors, selected installation of insulation jacketing and missile/jet impingement barriers.

The recirculation sumps at both Unit 2 and Unit 3 are of a sufficient size to accommodate replacement screens with large surface areas. The containment sumps are considerably smaller, particularly for Unit 2. In order to address the issues associated with the relatively small Unit 2 containment sump Entergy is currently evaluating analysis, design and licensing basis options. These options are discussed further in the responses to Items 2(c) and 2(d)(iii).

Preliminary results indicate that the upper and lower bearings of the Internal Recirculation (IR) pumps may be affected by debris. Preliminary results also indicate that the fibrous debris that passes through the sump screens may collect to form a thin fiber bed below the core for certain primary system break locations. Resolution of these potential downstream issues may require equipment modifications and/or the use of an alternate evaluation approach as discussed further in the response to Item 2(c).

Following selection of the final design option, which will provide resolution to the above issues, detailed engineering in support of the modification will commence. This detailed engineering will include sump screen structural analysis, consistent with industry accepted practices and applicable regulatory guidance. The analyses completed to date or in process may be affected by the final design resolution of the sump screen blockage issues. These analyses will be revised as required to represent the final design.

Licensing basis changes will be required as a result of analyses or plant modifications made to ensure compliance with the regulatory requirements listed in the Applicable Regulatory Requirements section of the subject generic letter. Should a License Amendment Request (LAR) be required it will be submitted to the NRC by December 31, 2005. The potential for a LAR is further discussed in the response to Item 2(e).

Requested Information Item 2(b):

A general description of and implementation schedule for all corrective actions, including any plant modifications, that you identified while responding to this generic letter. Efforts to implement the identified actions should be initiated no later than the first refueling outage starting after April 1, 2006. All actions should be completed by December 31, 2007. Provide justification for not implementing the identified actions during the first refueling outage starting after April 1, 2006. If all corrective actions will not be completed by December 31, 2007, describe how the regulatory requirements discussed in the Applicable Regulatory Requirements section will be met until the corrective actions are completed.

Entergy Response to Item 2(b):

The response to 2(a) provided a list of completed, in progress and planned activities needed to address the subject generic letter. The following design and related actions, as determined to be required, are scheduled for completion prior to refueling outages 2R17 and 3R14 for Unit 2 and Unit 3 respectively, but not later than December 31, 2007. Currently 2R17 is scheduled for April, 2006 and 3R14 is scheduled for March, 2007.

- Available Net Positive Suction Head (NPSH) analysis
- Debris transport analysis
- Downstream effects evaluation
- Development of conceptual design options
- Determination of debris head losses (sump screen surface areas)
- Selection of the final design
- Selection of sump screen hardware vendor
- Design and structural analysis of replacement sump screens
- Design and structural analysis of debris interceptors and flow diversion barriers
- Design of missile/jet impingement barriers
- Design of insulation jacketing
- Assessment of margin to address chemical effects
- Procedural revisions and enhancements
- Programmatic revisions and enhancements

The selection of the sump screen vendor is in progress and will be completed shortly. The debris transport and downstream effects evaluations are also nearing completion. An update of these activities will be submitted to the NRC by December 15, 2005.

The replacement of the sump screens and attendant modifications are currently scheduled to be completed during refueling outages 2R17 and 3R14.

The following items have currently been identified as activities that may require additional evaluation or additional testing to confirm or validate various assumptions used in the sump evaluation methodology. These activities are discussed further in other sections of this response:

- Chemical effects testing
- Downstream effects evaluation
- Scanning Electron Microscope (SEM) test for asbestos containing thermal insulation
- Zone of Influence (ZOI) testing for qualified coatings
- Strainer debris bypass fraction test
- Strainer head loss performance test including thin bed invulnerability demonstration
- Debris interceptor performance test

The following key activities and/or predecessors that could impact final design and planned installation are:

- Chemical effects testing results
- Results of the downstream effects evaluation on the fuel and system components
- Results of evaluations associated with the Unit 2 containment sump
- Final design selection and hardware delivery

Entergy intends to complete all design, procurement, fabrication, delivery and installation of replacement sump screens and attendant modifications that will meet or exceed all applicable regulatory requirements for post-accident sump performance by startup from the 2R17 and 3R14 outages, but no later than December 31, 2007.

As noted above, a number of challenges exist with respect to the need for additional analyses, testing and key activities/predecessors, most notably issues associated with the Unit 2 containment sump related to its small size and the downstream effects evaluation for the fuel.

As indicated above, Entergy will supplement this response by December 15, 2005 to provide an updated status of the requested information.

Requested Information Item 2(c):

A description of the methodology that was used to perform the analysis of the susceptibility of the ECCS and CSS recirculation functions to the adverse effects of post-accident debris blockage and operation with debris-laden fluids. The submittal may reference a guidance document (e.g., Regulatory Guide 1.82, Rev. 3, industry guidance) or other methodology previously submitted to the NRC. (The submittal may also reference the response to Item 1 of the Requested Information described above. The documents to be submitted or referenced should include the results of any supporting containment walkdown surveillance performed to identify potential debris sources and other pertinent containment characteristics.)

Entergy Response to Item 2(c):

Each of the containments of the Indian Point Units comprises three main floor levels: an operating floor at El. 95'; an intermediate floor at El. 68'; and a basement floor at El. 46' that contains the reactor cavity and two sumps; the recirculation sump and the containment sump. Gratings on the floors at El. 95' and 68' provide paths for the flow of water from the higher levels of the containment to the sumps.

The two sumps for each of the Units are independent of each other. The recirculation sump serves the two 100% capacity IR pumps, which are the preferred source of cooling in the recirculation phase of an accident. The containment sump serves as a backup to the recirculation sump, and feeds two 100% capacity Residual Heat Removal (RHR) pumps located outside containment. The containment sump is not placed in service unless the IR pumps, or associated flowpaths, are unavailable. The two sumps are at the same floor elevation but in different quadrants of containment.

The primary safety concerns regarding long term recirculation cooling following a LOCA are the LOCA-generated and pre-LOCA debris materials transported to the recirculation and containment sumps. This debris can result in adverse blockage effects and post-LOCA hydraulic effects, the combination of which can have an adverse effect on the long term recirculation function. An additional concern is the impact of sump screen debris bypass on downstream components in the ECCS and CSS systems, and in the reactor vessel, during long term recirculation.

Entergy has performed and continues to perform analyses to determine the susceptibility of the ECCS and CSS recirculation functions to adverse effects of post-accident debris blockage and operation with debris-laden fluids. These analyses identified those high energy lines that, if ruptured, could require the use of ECCS and CSS recirculation, the rupture locations that produce significant quantities of debris that may challenge the recirculation function, the zone within which the break forces will be sufficient to damage materials and create debris, the amount of debris generated and the characteristics of the debris. These analyses conform to the greatest extent practicable to the NEI GR (Ref. 1) as supplemented by the NRC SER (Ref. 2). Details of these analyses are provided below.

The primary contractor for these analyses is Enercon Services. Subcontractors supporting Enercon are Westinghouse and Alion Science and Technology.

Debris Sources and Generation

A review of the accident analysis and operational procedures was performed to determine the scenarios that require ECCS or CSS to take suction from the recirculation and containment sumps. It was determined that Large Break Loss of Coolant Accidents (LBLOCAs) and certain Small Break Loss of Coolant Accidents (SBLOCAs) require sump operation. Other High Energy Line Breaks (HELBs) were considered and it was determined that sump operation for these HELBs is not required. It was also determined that the HELBs that may require recirculation are located within the crane wall inside containment.

Potential debris sources that could, in the event of a high-energy line break, challenge the performance of the recirculation and containment sump screens and ultimately the ECCS and the CSS were identified. The amount of debris generated during and following a loss of coolant accident was based on the debris sources within the containment and the location and type of pipe break. The types, quantities and locations of the potential debris sources (including insulation, coatings, and dirt/dust) were identified using plant insulation drawings, specifications and/or walkdown reports and surveillances.

The Unit 2 containment walkdowns were completed in November, 2004. These walkdowns were performed in accordance with the guidance provided in NEI 02-01 (Ref. 3). A latent debris walkdown was performed in accordance with NEI GR and the NRC SER, with the exception of a sampling survey for dust, dirt, and lint. In the absence of this sample, the Unit 3 latent debris quantities were assumed to be applicable to Unit 2. This assumption will be verified during a confirmatory Unit 2 walkdown.

The Unit 3 containment walkdowns were completed in April, 2005. These walkdowns were also performed in accordance with the guidance provided in NEI 02-01 (Ref. 3). A latent debris walkdown was performed in accordance with NEI GR and the NRC SER, and included a sampling survey for dust, dirt, and lint.

<u>Debris Generation Analysis</u>

Break selection consisted of determining the size and location of the HELBs that would produce significant quantities of debris and potentially challenge post-accident sump performance. The debris inventory and the transport path were examined when making this determination.

In accordance with Regulatory Guide 1.82, Rev. 3 (Ref. 4) and the NEI GR guidance report, the method used for estimating the amount of debris generated by a postulated LOCA is based on a spherical zone of influence (ZOI). Thus, the evaluation of debris generation for a given break location consisted of establishing an appropriate ZOI, mapping that ZOI volume over the spatial layout of piping and components, calculating the quantity of debris source material within that ZOI, and determining the size distribution of the debris.

The spherical ZOI was truncated whenever the ZOI intersected robust barriers. The only robust barriers considered for all of the break locations were the primary shield wall, the crane wall, the operating deck, the RHR heat exchanger/ internal recirculation pump enclosure, and other robust concrete structures. No shadowing by large components within the north and south compartments inside the containment was credited.

At Indian Point Unit 2, five types of insulation were identified inside the crane wall during the containment walkdowns: Nukon® Low Density Fiberglass (LDFG), Transco Blanket (LDFG), Temp-Mat High Density Fiberglass (HDFG), Asbestos (particulate), and Reflective Metallic Insulation (RMI). For Unit 3, eight types of insulation were identified inside the crane wall:

Calcium Silicate, Nukon® (LDFG), Mineral Wool, Temp-Mat (HDFG), Asbestos (particulate), unclassified Fiberglass, Fiber Board, and RMI.

Debris sources that may dislodge and become transportable as a result of the harsh containment environment and effects of containment sprays were also evaluated. These sources include unqualified coatings, degraded qualified coatings, tags, labels, tapes, dust, and dirt. The insulation inside the containment building contains adequate covering to prevent containment spray flow or break flow from eroding insulation that is not destroyed during the LOCA event.

The specific break locations considered include breaks that: (1) generate the largest quantity of debris, (2) generate two or more different types of debris, (3) breaks in the most direct path to the sump and (4) large breaks with the largest potential particulate debris to fiber ratio. There are many breaks that could generate a small quantity of fibrous debris that would be necessary to form the theoretical 1/8" thin bed. As a result, the strainers to be designed will require a relatively large surface area with a complex geometry. Entergy plans to install replacement strainers with demonstrated invulnerability to development of a thin fiber bed.

Debris generation analyses were performed for the Baseline Analyses utilizing the debris specific ZOIs, in accordance with the NEI GR as supplemented by the NRC SER. Additionally, Analytical Refinement Analyses were performed considering ZOI size reductions and refined characterization of the generated debris. The debris generation analyses for the base and the refinement cases are described below.

Debris Generation (Baseline Analyses)

Baseline debris generation analyses were performed using the methodology, destruction pressures and ZOIs provided in the NRC SER and NEI GR. For materials for which specific data is not provided in the NEI GR, this analysis considers the destruction pressures and ZOI for the most limiting or comparable material. Additionally, the most limiting size distribution is considered for these materials.

For instance, a recommended destruction pressure and ZOI for asbestos insulation is not provided in the NEI GR. Therefore, the asbestos type insulation was assumed to have destruction properties equivalent to the NEI GR category having the lowest destruction pressure (ZOI=28.6D). The destroyed insulation inside the ZOI was assumed to fail as 100% fines.

For the baseline analyses, the large quantity of potentially adverse debris generated and the amount of debris expected to be transported to the sump has the potential to challenge the largest replacement strainers that can be located in the recirculation and containment sumps. Therefore, in order to more accurately predict a reduced amount of debris generated, analytical refinement analyses were performed.

Debris Generation (Analytical Refinement Analyses)

The quantity of transportable debris from the LOCA can be reduced by application of analytical refinements in the form of increased destruction pressures (reduced ZOI) and refined characterization of generated debris. The specific refinements, the corresponding effect on debris generation, and the specific activities required to implement these refinements are discussed below.

(a) The size distributions for LDFG and HDFG Insulation Debris were based on an Alion Science and Technology proprietary analysis that provides refinements to the NEI GR methodology for determining size distributions for fiberglass materials. NRC SER Section 4.2.4 suggests that the LOCA generated fibrous insulation debris could be separated into four distinct size classifications. The proprietary Alion analysis categorizes fibrous materials into fines, small pieces (< 6"), large pieces (> 6"), and intact pieces and are defined based on incremental destruction pressure zones.

(b) It was assumed that qualified coatings have a ZOI of 4D. This ZOI for qualified coatings is judged conservative based on the fact that the initial reactor coolant system pressure is significantly less than the pressures utilized to remove coatings using water-jet technology. In addition, industrial experience with water-jet technology to remove coatings requires application of a high-pressure jet at close proximity to the coated surface for extended periods of time. In contrast, the time period of blowdown for a PWR reactor coolant system due to a LBLOCA is on the order of 30 seconds and the break discharge pressure decreases over the duration of the blowdown period.

The 4D ZOI assumption for qualified coatings will require technical justification that may include specific coatings debris generation testing.

(c) It was assumed that asbestos insulation with jacketing has the same destruction properties as calcium silicate with jacketing. The NEI GR and NRC SER do not provide a recommended destruction pressure or ZOI for asbestos insulation. However, most commonly used asbestos insulation material is actually calcium silicate with asbestos fiber.

This assumption will require technical justification that may include verification testing (including Scanning Electron Microscope (SEM) examination) to demonstrate that the asbestos with jacketing has comparable characteristics as calcium silicate with asbestos fiber.

(d) It was assumed that all unqualified coatings, excepting inorganic zinc, outside of the coatings ZOI fail as chips. The size of chips or flakes was assumed to be equivalent to the smallest applied coating thickness. All coatings inside the ZOI and inorganic zinc outside the ZOI were assumed to have a 10 micron particle coating debris size.

A BWR Owner's Group (BWROG) report "Failed Coatings Debris Characterization" utilized autoclave test data gathered by the BWROG Containment Coating Committee to simulate LOCA exposure and gain insight into post-LOCA failure mechanisms. The result showed that all but the inorganic zinc paint failed as macro-sized pieces.

(e) It was assumed that stainless steel jacketing will be installed on insulated piping with asbestos with cloth. As stated in Item (c) above, it is expected that the asbestos insulation is essentially calcium silicate with asbestos fiber. Therefore, the ZOI for calcium silicate with stainless steel jacket was used in the debris generation analysis refinements.

This assumption requires the installation of steel jacketing on certain cloth covered asbestos piping insulation.

Debris Transport

Computational Fluid Dynamics (CFD) analyses are currently being performed to determine recirculation debris transport assessments. These analyses are being performed by Alion Science and Technology and Enercon Services.

The CFD model is used to determine the local fluid velocities and turbulence levels in the post-LOCA containment pool, as the recirculation water flows from the broken pipe and containment sprays to the sump strainers. The fluid velocities and turbulence levels are indicative of the ability of assorted sizes and types of debris to settle in the flow field. Areas with low velocities allow smaller debris sizes to settle, while larger velocities and/or turbulence levels indicate areas where debris may remain in suspension or roll along the floor and consequently, be more readily transportable to the sump.

The CFD results show that coolant discharged from the break and the containment sprays flows directly to the sumps. Any debris dispersed along the containment floor within the crane wall has a high potential for transport to the sumps. The large quantity of potentially adverse debris types and the debris expected to be transported to the sumps has the potential to challenge the largest replacement strainer that can be accommodated in the recirculation and containment sumps, for both the baseline and refinement debris generation cases.

Consequently, remedial actions to reduce the amount of debris transported to the sump may be warranted.

Debris Transport Reduction

In addition to the analytical refinements discussed above, reductions in debris transport can be achieved by plant configuration changes that minimize flow velocities and turbulent kinetic energy. The current containment layout is not conducive to debris settlement. Flow channeling, which involves diverting or distributing flows to reduce average velocities and turbulence levels offer a relatively efficient method for reduction of debris that is transported to the sumps.

A review of the containment layout offers a unique solution for debris reduction utilizing flow channeling by diverting break flows inside the crane wall through the reactor cavity/in-core tunnel and then towards the sumps. The reactor cavity/in-core tunnel offers an expansive area that produces velocities low enough to allow settlement of small and large debris pieces, free from the turbulence inducing break flow and containment spray effect. Additionally, debris entering the reactor cavity/in-core tunnel is not expected to erode due to the very low flow velocities within the in-core tunnel. Consequently, only fines and particulate matter may remain transportable.

In addition to flow channeling, debris interceptors provide a means for trapping entrained debris prior to reaching the recirculation and containment sump screens. The utilization of flow channeling through the reactor cavity/in-core tunnel, which eliminates the small and large debris pieces, requires that only fines and particulate debris be trapped using debris interceptors. If it is determined that debris source term reduction can be realized with use of debris interceptors, it is anticipated that debris interceptors may be located near the recirculation and containments sumps and outside the crane wall.

The CFD model will be revised, as required, to determine the debris transport during the detailed design phase for the replacement sump screens and associated modifications. Inputs will include the sump flows, the configuration of the flow channel, flow diverters, and the crane wall openings that are being considered in the proposed conceptual design.

Net Positive Suction Head and ECCS Pumps

For the IR and RHR pumps, a new analysis is currently in process that is expected to provide an increase in calculated NPSH margins. In order to determine the required strainer size, conservative NPSH margins limits, representing the debris head loss limits have been established. These debris head loss limit values, provided in Table 1, are expected to bound the recalculated NPSH margins.

The available NPSH values will be determined for a given containment flood elevation level for both LBLOCA and SBLOCA scenarios. In accordance with Regulatory Guide 1.82, Rev. 3 (Ref. 4), the calculated height of water on the containment floor did not consider quantities of water that do not contribute to the sump pool, nor that amount of water in enclosed areas that cannot be readily returned to the sump. In addition, conservative assumptions will be made regarding sump temperature and containment pressure conditions. It is expected that credit will not be taken for containment overpressure provided the replacement sump screens do not extend above the containment floor.

The IR and RHR pump NPSH margins will be determined for the most limiting pump flow rates corresponding to the limiting post accident system alignments. The Unit 3 IR pump NPSH margins will be based on the replacement IR pumps. In addition, the available NPSH will be calculated using the water level downstream of proposed new openings in the crane wall. The containment water level downstream of the new openings in the crane wall in the conceptual design is expected to have draw-down of approximately 2 inches at a sump flow rate equivalent to both IR pumps operating.

Debris Accumulation and Head Loss

The required strainer surface areas for the debris transported to the recirculation and containment sumps were estimated using the debris head loss limits provided in Table 1, to ensure that adequate NPSH margins are maintained. The industry accepted NUREG/CR-6224 correlation (Ref. 6) was used in these estimations.

The required Unit 2 strainer surface areas are estimated to be 1800 ft^2 and 1025 ft^2 for the recirculation and containment sumps, respectively. The corresponding Unit 3 strainer areas are 1350 ft^2 and 800 ft^2. These surface areas consider debris generation refinements and the transport model representing flow channeling through the reactor cavity/in-core tunnel, but do not include chemical effects. (See the Chemical Effects section below for how chemical effects are being addressed.)

Upstream Effects

The upstream effects evaluations include the completed containment flooding calculations and the ongoing CFD analyses that are being used to perform recirculation transport assessments. The containment flooding analysis considered holdup areas to minimize containment level for NPSH assessments. Such areas included the refueling cavity, operating floor, intermediate level, and other miscellaneous holdup volumes. The CFD methods are being used to determine the local fluid velocities and turbulence levels in the post-LOCA containment pool, as the recirculation water flows from the broken pipe and containment sprays to the sump strainers. A three dimensional (3-D) CAD model of the containment is used in the CFD analysis which is currently in progress and includes all significant features in the containment up to the post-LOCA containment flood level. The model includes all significant structures such as, concrete walls, structural steel, and large tanks & equipment that could impede or affect the flow of water to the sump.

Downstream Effects

An evaluation is currently being performed to assess the potential for wear, abrasion and debris clogging of flow restrictions downstream of the sump screens to ensure long term recirculation cooling and containment pressure and temperature control. Those flowpaths and components of the ECCS and CSS that are required to operate during recirculation are under evaluation. The evaluation is determining the susceptibility of those flowpaths, and components in those flowpaths, to wear and abrasion as well as obstruction due to debris that may pass through the recirculation and/or containment sump screens. These components and flow paths include, but are not limited to, containment spray nozzle openings, High Head Safety Injection (HHSI) throttle valves, coolant channel openings in the core fuel assemblies, fuel assembly inlet debris screens, ECCS pump seals, bearings, and impeller running clearances.

The current containment and recirculation sumps contain wire mesh screens with 1/8" x 1/8" square openings. In the evaluation, due to the large debris load, it is assumed that replacement screens having a larger surface area and 1/8" diameter circular openings would be installed. The evaluation uses debris size values from WCAP-16406-P (Ref. 5).

The IR, RHR and HHSI pump vendor is performing an evaluation of the susceptibility of these pumps to blockage and wear and abrasion effects due to the debris concentration determined to be in the recirculating fluid.

Preliminary results of the downstream effects analysis indicate that the majority of components are not susceptible to clogging or undue wear and abrasion including the RHR and HHSI pumps. However, these preliminary results also indicate that the upper and lower bearings of the IR pumps may be affected by debris. Preliminary results also indicate that the fibrous debris that passes through the sump screens may collect to form a thin fiber bed below the core for certain primary system break locations. Resolution of these potential downstream issues may require equipment modifications and/or the use of an alternate evaluation approach as discussed under Alternative Evaluation below.

Chemical Effects

In the replacement recirculation and containment sump screen designs, margin for an increased head loss due to chemical effects will be included. The technical justification for the chemical effects head loss will be based on a plant specific materials evaluation that will determine whether the joint NRC/EPRI integrated chemical effects test (ICET) parameters bound the plant conditions. If the chemical effects test conditions do not bound the plant specific conditions a plant specific evaluation may be required.

Alternate Evaluation

In addition to the evaluations reported above, the application of the methods defined in Section 6.0, "Alternate Evaluation," of Volume 1 of the NEI GR (Ref.1), considering the limitations and clarifications as approved by the NRC SER (Ref. 2), is being considered. This alternate analysis methodology allows for use of an alternate break size in design basis analyses of containment recirculation performance. As part of implementing the alternate evaluation approach, it would be demonstrated that reasonable assurance of mitigation capability is retained for break sizes between the alternate break size and the double-ended guillotine break of the largest pipe in the reactor coolant system.

This alternate analysis is being considered to address challenges associated with the small size of the Unit 2 containment sump as well as to address certain downstream effects currently under evaluation.

Requested Information Item 2(d)

The submittal should include, at a minimum, the following information:

(i) The minimum available NPSH margin for the ECCS and CSS pumps with an unblocked sump screen.

(ii) The submerged area of the sump screen at this time and the percent of submergence of the sump screen (i.e. partial or full) at the time of the switchover to sump recirculation.

(iii) The maximum head loss postulated from debris accumulation on the submerged sump screen, and a description of the primary constituents of the debris bed that result in this head loss. In addition to debris generated by jet forces from the pipe rupture, debris created by the resulting containment environment (thermal and chemical) and CSS washdown should be considered in the analyses. Examples of this type of debris are disbonded coatings in the form of chips and particulates and chemical precipitants by chemical reactions in the pool.

(iv) The basis for concluding that the water inventory required to ensure adequate ECCS or CSS recirculation would not be held up or diverted by debris blockage at choke-points in containment recirculation sump return flowpaths.

(v) The basis for concluding that inadequate core or containment cooling would not result due to debris blockage at flow restrictions in the ECCS and CSS flowpaths downstream of the sump screen, (e.g., a HPSI throttle valve, pump bearings and seals, fuel assembly inlet debris screen, or containment spray nozzles). The discussion should consider the adequacy of the sump screen's mesh spacing and state the basis for concluding that adverse gaps or breaches are not present on the screen surface.

(vi) Verification that close-tolerance subcomponents in pumps, valves and other ECCS and CSS components are not susceptible to plugging or excessive wear due to extended post-accident operation with debris-laden fluids.

(vii) Verification that the strength of the trash racks is adequate to protect the debris screens from missiles and other large debris. The submittal should also provide verification that the trash racks and sump screens are capable of withstanding the loads imposed by expanding jets, missiles, the accumulation of debris, and pressure differentials caused by post-LOCA blockage under predicted flow conditions.

(viii) If an active approach (e.g., back flushing, powered screens) is selected in lieu of or in addition to a passive approach to mitigate the effects of the debris blockage, describe the approach and associated analyses.

Entergy Response to Item 2(d)(i):

The minimum available NPSH margin for the ECCS and CSS pumps with an unblocked replacement sump screen is dependent upon the replacement sump screen designs. This submittal will be supplemented by December 15, 2005 to include these values upon completion of the design of the replacement sump screens.

Entergy Response to Item 2(d)(ii):

The final design of the replacement sump screens has not been completed. However, it is expected that the final design will result in full submergence of the screens following a large break LOCA. Efforts will be made to ensure full screen submergence following a small break LOCA (SBLOCA). In case of partial screen submergence during a SBLOCA, it is expected that adequate gravity flow through the debris loaded strainer media will be demonstrated. The estimated screen areas of the Unit 2 replacement sump screens are approximately 1800 ft^2 and 1025 ft^2 for the recirculation and containment sumps, respectively. The corresponding Unit 3 strainer areas are 1350 $ft^2$and 800 ft^2. These are the estimated surface areas, utilizing the NUREG-6224 methodology (Ref. 6), to meet debris head loss limits listed in Table 1 without inclusion of chemical effects.

Entergy Response to Item 2(d)(iii):

The maximum calculated head loss across the replacement screens is dependent upon the replacement sump screen designs which as indicated previously have not been finalized. However, for conceptual design purposes, the maximum head loss limits of 0.25 ft and 1.0 ft (for single IR and RHR pump operation, respectively), due to debris accumulation on the submerged sump screens, considered in conjunction with the sump temperature with the most limiting NPSH margin, require approximate screen sizes of 1800 ft^2 and 1025 ft^2 for the Unit 2 recirculation and containment sumps, respectively. The corresponding Unit 3 strainer areas are 1350 $ft^2$and 800 ft^2. These screen sizes should be sufficient to accommodate debris that is transported to the sumps including debris sources that may dislodge and become transportable as a result of the harsh containment environment and effects of containment sprays. Additional sump screen surface area may be required as margin to accommodate the uncertainties associated with chemical effects.

The recirculation sumps at both Unit 2 and Unit 3 and the Unit 3 containment sump are of a sufficient size to accommodate the above noted screen areas plus additional surface area for margins required for chemical effects. The Unit 2 containment sump is considerably smaller, and may not be able to accommodate a 1025 ft^2 screen area.

In order to address the issues associated with the relatively small Unit 2 containment sump, Entergy is currently evaluating analysis, design and licensing basis options. In terms of analysis, consideration is being given to the application of the methods defined in Section 6.0, "Alternate Evaluation," of Volume 1 of the NEI GR (Ref.1) as supplemented by the NRC SER (Ref. 2). The design options under consideration include screen designs that allow higher screen surface areas to be placed within a given volume and possibly extending the sump screens outside of the containment sump. Entergy is also evaluating the feasibility of a containment sump licensing basis change. (See the response to Item 2(e) for further information on licensing basis changes.)

Conceptual designs are under development to reduce the magnitude of debris transported to the sump thereby reducing the required surface area.

The primary constituents of the insulation debris bed that result in screen head loss for Unit 2 are Nukon®, Asbestos, RMI, Temp-Mat and Transco Blanket. The Unit 3 primary constituents are Nukon®, Asbestos, Calcium Silicate, Temp-Mat, Fiberglass, and RMI. Additional debris sources include degraded qualified coatings, qualified coatings within the ZOI, unqualified coatings, latent debris, labels and tags. As indicated in the response to 2(c), screen head loss due to chemical effects is currently in planning.

Entergy Response to Item 2(d)(iv):

The water inventory required for ECCS and CSS recirculation will not be held up or diverted by debris blockage at choke-points in containment recirculation sump return flowpaths. This conclusion is based on evaluations and walkdowns conducted to look for potential choke-points in the return flowpaths to the sumps. The liquid inventory holdup evaluations showed acceptable post-LOCA water levels within containment and sufficient flow is provided to the recirculation and containment sumps.

The results of these evaluations were used to establish minimum water levels used in the debris transport and head loss calculations, as well as the conceptual design efforts discussed in this submittal.

Entergy Response to Item 2(d)(v):

As discussed in Response 2(c), the impact of debris passing through the strainers causing blockage in downstream components is currently under evaluation. The purpose of the evaluation is to determine whether the ECCS and portions of the CSS flowpaths could become blocked due to the debris that passes through the containment and recirculation sump screens. The evaluation utilizes the methods described in proprietary WCAP-16406-P (Ref. 5) and vendor evaluations. Both particulate and fibrous debris are considered in the evaluation. A sump screen round hole size of 1/8-inch is currently used as a basis for the evaluation. The replacement sump screen hole size is expected to be 1/8-inch or smaller. Preliminary results of the downstream effects analysis indicate that the majority of components are not susceptible to blockage. However, preliminary results indicate that the upper and lower bearings of the IR pumps and fuel assembly inlet strainers may be adversely affected by the debris/fibrous material that pass through the screens.

The final results of the downstream blockage analysis will be reported to the NRC by December 15, 2005.

Entergy Response to Item 2(d)(vi):

As discussed in Response 2(c), the potential for excessive wear, abrasion, and plugging of close-tolerance subcomponents in pumps, valves and other ECCS and CSS components due to ingestion of debris downstream of the sump screen is under evaluation. The evaluation is using the methods described in proprietary WCAP-16406-P (Ref. 5), vendor evaluations, and an assumed circular sump screen hole size of 1/8-inch.

Preliminary results of the downstream effects analysis indicate that the majority of close-tolerance components are not susceptible to undue wear, abrasion, and plugging including the RHR and HHSI pumps. However, these preliminary results also indicate that the upper and lower bearings of the IR pumps may be adversely affected by debris.

The final results of the downstream wear analysis will be reported to the NRC by December 15, 2005.

Entergy Response to Item 2(d)(vii):

As discussed earlier the structural evaluation of the replacement sump screens and any associated trash racks is dependent upon the replacement sump screen design selected for installation. This evaluation will be performed once a design has been selected and will be consistent with industry accepted practices and applicable regulatory guidance.

Entergy Response to Item 2(d)(viii):

An active approach has not been selected in lieu of a passive approach to mitigate the effects of debris blockage.

Requested Information Item 2(e):

A general description of and planned schedule for any changes to the plant licensing bases resulting from any analyses or plant modifications made to ensure compliance with the regulatory requirements listed in the Applicable Regulatory Requirements section of this generic letter. Any licensing actions or exemption requests needed to support changes to the plant licensing basis should be included.

Entergy Response to Item 2(e):

Licensing basis changes will be required as a result of analyses and plant modifications made to ensure compliance with the regulatory requirements listed in the Applicable Regulatory Requirements section of the subject generic letter. Changes to the plant licensing basis will be performed in accordance with 10CFR50.59. Currently, Entergy does not plan to submit License Amendment Requests (LARs) or exemptions requests in conjunction with the resolution of GSI-191 for Indian Point Unit 2 or Unit 3. However, as discussed in the response to 2(d)(iii), licensing basis options associated with the Unit 2 containment sump are under evaluation due to the challenges posed by its small size. Should these evaluations determine that a LAR or exemption request is warranted, such request will be submitted by December 31, 2005.

Requested Information Item 2(f):

A description of the existing or planned programmatic controls that will ensure that potential sources of debris introduced into containment (e.g. insulations, signs, coatings, and foreign materials) will be assessed for potential adverse effects on the ECCS and CSS recirculation functions. Addressees may reference their responses to GL 98-04, "Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System after a Loss-of-Coolant Accident Because of Construction and Protective Coating deficiencies and Foreign Material in Containment," to the extent that their responses address these specific foreign material control issues.

Entergy Response to Item 2(f):

Programmatic controls that will be implemented include the additional controls for qualified coatings, an insulation configuration control and inspection program and revised FME controls.

A qualified coatings program will be added to the controls already in place for the procurement, application, maintenance and assessment of qualified coatings. The inspection process currently includes a detailed visual inspection and documentation of coating status and deficiencies. The visual inspection will be augmented by the qualified coatings program.

The insulation configuration control program will be used to ensure that future potential sources of insulation debris will be controlled with respect to potential effects. The program will provide controls to maintain the inventory of insulation inside of containment such that the amount and type remains within the acceptable design margin for debris loading of the recirculation and containment sump suction strainers following a LOCA.

The revised containment FME program will ensure the containment FME programs will not introduce foreign materials that would adversely affect the ECCS and CSS recirculation functions. This program will also monitor the level of dirt/dust and latent fiber within the containment building.

References

1. Nuclear Energy Institute Document NEI 04-07, Volume 1, Revision 0, "Pressurized-Water Reactor (PWR) Sump Performance Methodology," dated December, 2004.

2. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to NRC Generic Letter 2004-02, published as Volume 2 of Nuclear Energy Institute Guidance Report (NEI 04-07) "Pressurized Water Reactor Sump Performance Evaluation Methodology," dated December, 2004.

3. Nuclear Energy Institute Report NEI 02-01, "Condition Assessment Guidelines: Debris Sources Inside PWR Containments," Revision 1, dated September, 2002.

4. Regulatory Guide 1.82, "Water Sources for Long-Term Recirculation Cooling Following a Loss-Of-Coolant Accident," Revision 3, November 2003.

5. WCAP-16406-P, "Evaluation of Downstream Sump Debris Effects in Support of GSI-191," June 2005.

6. NUREG/CR-6224, "Parametric Study of the Potential for BWR ECCS Strainer Blockage Due to LOCA Generated Debris," dated October 1995.

Table 1 Allowable Strainer Debris Head Loss

Sump	Pump Alignment	Allowable Debris Head Loss
Recirculation	One internal recirculation pump	0.25 ft
Recirculation	Two internal recirculation pumps	1.5 ft
Containment	One RHR pump	1.0 ft

INDIAN POINT UNIT 2 and UNIT 3

ATTACHMENT 2 TO NL-05-094

Update to Commitments made in the 90-Day Response to NRC Generic Letter 2004-02, Potential Impact Of Debris Blockage On Emergency Recirculation During Design Basis Accidents At Pressurized-Water Reactors

ENTERGY NUCLEAR OPERATIONS, INC
INDIAN POINT NUCLEAR GENERATING UNITS 2 AND 3
DOCKETS 50-247 AND 50-286

Number	Commitment	Due Date
1	Complete Indian Point Unit 3 containment walkdowns to support the analysis of susceptibility of the ECCS and CSS recirculation functions to the adverse effects of debris blockage identified in Generic Letter 2004-02.	Complete
2	Complete the analyses of the susceptibility of the ECCS and CSS recirculation functions for Indian Point Unit 2 and Unit 3 to the adverse effects of post accident debris blockage and operation with debris-laden fluids identified in Generic Letter 2004-02.	Prior to 2R17 and 3R14

Exhibit Q

Exhibit Q

UNITED STATES
NUCLEAR REGULATORY COMMISSION

In the matter of

ENTERGY NUCLEAR INDIAN POINT 2 L.L.C.,	)	
ENTERGY NUCLEAR INDIAN POINT 3, L.L.C,	)	License No. DPR 26 and
And Entergy Nuclear Operations, Inc.	)	License No. DPR 64
and Entergy Northeast, Inc.,	)	
regarding the Indian Point Energy Center	)	Docket No. 50-247 and
Unit 2 and Unit 3License Amendment	)	Docket No. 50-286
Regarding Fire Protection Program	)	

SUPPLEMENTAL DECLARATION OF ULRICH WITTE
REPLY ENTERGY'S RSEPONSE AND STAFF'S RESPONSE TO PETITION FOR LEAVE TO INTERVENE, REQUEST FOR HEARING, AND CONTENTIONS REGARDING LICENSE RENEWAL OF INDIAN POINT UNIT 3 AND UNIT 2
RE: CONTENTIONS 22-25

My name is Ulrich Witte. WestCAN, RCCA, PHASE, the Sierra Club—Atlantic Chapter, and Assemblyman Richard Brodsky have retained 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 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 Exhibit O.

I submit the following comments in support of each coalition stakeholder in Contentions 22-25 regarding the original design, construction and operation of the plant, and their relevancy to the license renewal application as delineated in 10CFR Part 54.21, "Contents of the application,-general information" and 10CFR50.54.22 , "Contents of the application – technical information," and 10CFR54.31 "Continuation of the CLB and conditions of renewed license" as contained in the License Renewal Proceedings of Indian Point Unit 2 and 3.

Contention:

The Applicant was not required to comply with the federal approved general design criteria, contained in the Code of Federal Regulations (CFR) and instead used trade guidance for Indian Point 2 and 3. as opposed to of General Design Criteria for current design, and the current operating license and with regard to the Applicant's LRA for an additional 20 years of operation

The design criteria based upon trade guidance, was misrepresented by the Applicant in the renewal application as conforming to draft criteria published in 1967, and then relieved of all conformance to essentially all committed design criteria under a letter published by the Office of Nuclear Reactor Regulation in 1992.

The historical record shows that the applicant after discovering the error, failed to remediate the violation, and the misrepresentation, and therefore, indicates a breakdown in implementing and enforcing the provisions of the Administrative Procedures Act.

This 40 year old design criteria problem affects both plants, and leaves Indian Point without adequate safety margins and the New York Metropolitan region without adequate assurance of protection of public health and safety

Submitted with particularity and specificity are provided here in for Unit 2. Unit 3 contains a similar historical record. The records show that the issue exists for both plants.

In essence, the aging management program required for license extension is predicated upon a sound, compliance and complete design basis record. Without this, the plant's material condition, basis design assumptions required for license renewal cannot be substantiated by prerequisite in situ conditions of essentially all aspects of each ageing plant.

Both respondents argues the legal ground of the general design criteria. Whereas neither Staff nor Entergy takes issue with the historical events leading to our conclusion. The regulatory history regarding applicability is not contested as documented on the table beginning on page 169 of the petition. Entergy argues that we simply arrived at the incorrect conclusion. Even with Unit 3, for example, stating in Section 1.3 of the UFSAR that it complies with the GDCs, Entergy's counsel states with respect to contentions 10, 11A and 22, 23, 24, and 25 that ***neither plant is committed to the GDCs at all.***

Much on point, there is a substantial error in Entergy's response. Page 59 of the Applicant' response states the following:

> The GDC, which are contained in Appendix A to 10 C.F.R. Part 50, establish minimum requirements for the principal design criteria for water-cooled nuclear power plants. As set forth in NRR Office Instruction LIC-I00, Revision 1, *the GDC are not applicable to plants with construction permits issued prior to May* 21, 1971. The construction permits for Indian Point Units 2 and 3 were issued before that date; on October 14, 1966, and August 13, 1969, respectively. *Thus, the GDC do not apply to those plants*. [emphasis added]

This is a substantial error. The reliance of Energy and Staff of the legality of LIC 100 is misguided—the document is far from authoritative. See Exhibit W. There are literally 100s of places in the license basis where the applicant directly or by inference states that he or she intends to comply with the GDC in question so as to answer the notice, letter, order or tiered licensing document.

Several examples are provided. A very high tier document is the plant Technical Specification Manual. This is essentially the undisputed black letter set of rules that the plant must conform to operate within its license conditions, and technical limits to operational actions are required for off-normal events, or design basis accidents.

The TRM cites B 3.1 REACTIVITY CONTROL SYSTEMS, B 3.1.3 Moderator Temperature Coefficient (MTC), that ***GDC 11 is required***. GDC 11 for this application is the *final GDC dated May 21, 1971*. According to GDC 11 (Ref. 1, in the TRM), "the reactor core and its interaction with the Reactor Coolant System (RCS) must be designed for inherently stable power operation, even in the possible event of an accident. In particular, the net reactivity feedback in the system must compensate for any unintended reactivity increases."

In addition, on page 65 of the file, and The meteorological monitoring instrumentation system was installed to meet the requirements, in part, of 10 CFR 50 Appendix A (again, the TRM cites Ref.1), Title 10, Code of Federal Regulations, Part 50 Appendix A, Criterion 64, "Monitoring Radioactivity Releases." <u>See exhibit Y</u>

Just by making this statement in their response they essentially invalidate and discredit their entire license renewal application, and there January 22nd response.

In fact, any statement they make in the LRA, or in responses to RAIs, or legal proceeding may be interpreted as *a possible modification to the CLB*. A statement "thus, the GDC do not apply to those plants," (see page should have Staff more than just a little agitated. A second occurrence is found on Page 64, of Entergy's reply contention 11B renewal. "As a threshold matter, IPEC Units 2 and 3 are not subject to the GDC...further, to the extent WestCAN is challenging the underlying design of the facility, such matters are beyond the scope of this proceeding and are inadmissible as a matter of law." One cannot fathom that with these kinds of fundamental errors, of what design criteria the plant is required to be engineered, designed and operated to, it is beyond sound engineering, that one can somehow apply engineering analysis to any aspect of the rules of 10CFR54.

A second example is provided in Exhibit P. In this example, NRC BULLETIN 2003-02: leakage from reactor pressure vessel lower Head penetrations and reactor coolant pressure Boundary integrity is at issue. On page 4 of Entergy's response to the Bulletin (included in Exhibit M), the applicant states "Also, the information provided in Section 3, Regulatory Requirements, of MRP-48 (Reference 1) is applicable for the IP2 and IP3 RPV lower head. ***Compliance with the applicable general design criteria (GDC 14, 31, and 32) is discussed in the Updated Final Safety Analysis Reports for IP2 and IP3.***"

Control room habitability is a third example.

We stand firm that admissibility threshold is met for all six criteria. We disagree with the Applicants complaint of lack of particularity and specificity. These examples should have been ferreted out the Applicant prior to wasting so many resources in and the public health and safety at risk for so many years and not suggesting 20 more.

Essentially every other element of safety and hinges on integrity, control and management of the licensing and design basis, and compliance with the law, and lawful operation of the facility. One would think one could simply examine the SER, along with the rest of the CLB circa the original operating license granted and find transparent the records for design basis, construction, licensing conditions, maintenance and safe operation of the plant.

After careful examination of the facts, as represented in the table of events, it appears that just the opposite is true. Applicable rules as found in 10 CFR are not followed, and in fact it appears the applicant and the regulator are under "discretionary enforcement" or other unlawful bypassing of the rules such as LIC-100, the opposite routinely. Bypassing the core protection provided to the public under the Administrative Procedures Act is un acceptable.

The past and present owners of Indian Point have failed for forty years to ensure that the nuclear reactor(s) are in compliance with regulations established by the US Nuclear Regulatory Commission to ensure public health and safety.

In its application for a 20-year license extension, Entergy has misrepresented the official record of the Federal Register to give a false appearance of compliance with regulations. In fact, the reactors have been out of compliance since they were granted its original operating license 40 years ago.

The License Renewal Rule requires the applicant to identify which set of rules and regulations the reactor complies to (NRC regulations have been changed and updated several times since the 1960's.) However, the Applicant and the NRC are unable or unwilling to state which regulations are applicable to Indian Point.

The Nuclear Regulatory Commission has failed in its responsibilities by allowing Indian Point to operate under a set of "guidelines" proposed forty years ago by an industry lobbying group, but never approved by the NRC's mandatory "rule-making" process.

The results of this are painfully obvious. A plant that that experienced a design basis event tube rupture, spent fuel pools leaking, and piping leaking. Establishing and maintaining the design basis is impossible, when the core general design criteria are simply set aside.

The smoking gun is evident in the complete version of the 1968 DDFSAR. I cannot endorse relicensing the Indian Point Unit 2 facility based upon the record and the facts of the historical record up to and including the current statements contained the Applicants LRA regarding the construction, management, and safe operation of the plant being in compliance with the draft general design criteria published in the Federal Register in 1967, with the 1968 DDFSAR Report (see petition filed December 10, 2007) stating otherwise.

I declare under the penalty of perjury that the foregoing is true and correct.

Executed this 15th day of February, 2008.

UWitte

Ulrich K. Witte

State of New York)
)ss.:
County of Rockland)

On the 15th day of Feb., in the year 2008 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.

Notary Public

SUSAN HILLARY SHAPIRO
Notary Public - State of New York
No. 02SH6060466
Qualified in Rockland County
My Commission Expires June 25, 2008

Exhibit R

Entergy

Entergy Nuclear Northeast
Indian Point Energy Center
295 Broadway, Suite 1
P.O. Box 249
Buchanan, NY 10511-0249
Tel 914 734 5340
Fax 914 734 5718

Fred Dacimo
Vice President, Operations

November 13, 2003

Re: Indian Point Units 2 and 3
Dockets 50-247 and 50-286
NL-03-178

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

Subject: **90-Day Response to NRC Bulletin 2003-02 Regarding Leakage From Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity**

Reference: 1) NRC Bulletin 2003-02, "Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity," dated August 21, 2003

Dear Sir:

Pursuant to 10 CFR 50.54(f), Entergy Nuclear Operations, Inc (Entergy) is hereby providing the response to Bulletin 2003-02 (Reference 1) for Indian Point Unit 2 (IP2) and Indian Point Unit 3 (IP3). The information requested by the Bulletin is provided in Attachment 1.

The U.S. Nuclear Regulatory Commission issued the Bulletin to advise licensees that current methods of inspecting Reactor Pressure Vessel (RPV) lower heads may need to be supplemented with additional measures to detect reactor coolant pressure boundary leakage. Licensees are required to provide information regarding RPV lower head inspection programs previously implemented and plans for future inspections to address observations identified in the Bulletin. Since the next refueling outages for IP2 and IP3 are after December 31, 2003 (Fall 2004 and Spring 2005, respectively), this response is due within 90 days of the Bulletin date.

The last inspections of the RPV lower heads for IP2 and IP3 were performed during the prior refueling outages, Fall 2002 and Spring 2003, respectively. A description of these inspections is provided in Attachment 1 in response to item (1)(a) of the Bulletin. Based on recommendations developed by the industry's Material Reliability Program, Entergy has prepared an expanded inspection program for the RPV lower head. A description of the inspections planned for future outages is provided in Attachment 1 in response to item (1)(b) of the Bulletin.

The Bulletin also requires that a post-inspection report be submitted to the NRC within 60 days following restart from the next refueling outage. Entergy agrees to provide the requested information as specified in item (2) of the Bulletin.

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There are no new commitments being made in response to this Bulletin. If you have any questions regarding this submittal, please contact Kevin Kingsley at (914) 734-5581.

I declare under penalty of perjury that the foregoing is true and correct. Executed on 11/13/03

Sincerely,

Fred R. Dacimo
Vice President, Operations
Indian Point Energy Center

cc: Mr. Patrick D. Milano, Senior Project Manager
Project Directorate I,
Division of Licensing Project Management
U.S. Nuclear Regulatory Commission
Mail Stop O-8-C2
Washington, DC 20555-0001

Mr. Hubert J. Miller
Regional Administrator, Region 1
U.S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406-1415

Resident Inspector's Office
Indian Point Unit 2
U.S. Nuclear Regulatory Commission
P.O. Box 38
Buchanan, NY 10511-0038

Resident Inspector's Office
Indian Point Unit 3
U.S. Nuclear Regulatory Commission
P.O. Box 337
Buchanan, NY 10511-0337

<u>ATTACHMENT 1 TO NL-03-178</u>

90-DAY RESPONSE TO NRC BULLETIN 2003-02

Entergy Nuclear Operations, Inc
Indian Point Nuclear Generating Units 2 and 3
Docket No 50-247 and 50-286

90-DAY RESPONSE TO NRC BULLETIN 2003-02 REGARDING LEAKAGE FROM REACTOR PRESSURE VESSEL LOWER HEAD PENETRATIONS AND REACTOR COOLANT PRESSURE BOUNDARY INTEGRITY

Requested Information Item (1)(a):

A description of the RPV lower head penetration inspection program that has been implemented at your plant. The description should include when the inspections were performed, the extent of the inspections with respect to the areas and penetrations inspected, inspection methods used, the process used to resolve the source of findings of any boric acid deposits, the quality of the documentation of the inspections (e.g., written report, video record, photographs), and the basis for concluding that your plant satisfies applicable regulatory requirements related to the integrity of the RPV lower head penetrations.

Entergy Response:

During the most recent refueling outages for each unit, inspections were performed as an extension of actions that were taken to assess pressure boundary integrity for Alloy 600 penetrations in the RPV upper head. The scope and results of the most recent inspections are summarized below. A description of the RPV lower head penetrations and insulation configuration is also provided to support the inspection discussions provided in this response.

Description of RPV lower heads at IP2 and IP3:

There are 58 penetrations, nominally 1.5 inches in diameter, in the RPV lower head for the incore instrument nozzles. An Alloy 600 tube extends through each penetration and the tubes are welded at the inside surface of the lower head. Each penetration is surrounded by a ¼-inch thick weld pad at the outside surface of the lower head. Discussions with the vessel fabricator indicate that the intent of this feature was to facilitate weld repair of an incore instrument nozzle.

The RPV lower head is covered with reflective metal insulation, approximately 3 to 3.5 inches thick, and contoured to the profile of the head. This insulation is part of the overall reactor vessel insulation package and is not designed to be removable. There is a 2.5 to 3 inch diameter hole in the insulation at each penetration, resulting in a ½ to ¾ - inch annular gap between the tubing outside diameter and adjacent insulation. This gap is filled with steel wool and capped with a metal ring that is secured with four screws to the insulation package.

IP2 Inspection During 2R15:

The latest inspection of the IP2 RPV lower head was performed in November 2002, during refueling outage 2R15. This inspection consisted of a visual inspection, without insulation removal, performed by a VT-2 qualified individual, as well as engineering personnel. The inspection scope included the outside surface of the lower head insulation and the 58 locations where the incore instrument nozzles penetrate through the insulation.

Although the inspection identified white streaks and some brown rust streaks on the outside of the insulation, there were no signs of inservice leakage attributed to RPV lower head penetrations. The observed streaking was considered characteristic of leakage that initiated outside of the insulation. Two possible sources of this leakage were (1) refueling cavity seal leakage or (2) refueling cavity liner leakage. Based on a review of the observations, Entergy concluded that there was no evidence of pressure boundary leakage at the lower head.

Since the above inspection of the IP2 lower reactor vessel head identified no through-wall leakage it was determined that the integrity of the lower vessel head, including the Alloy 600 penetrations remained within the applicable ASME Code and other regulatory requirements identified in the Bulletin.

IP3 Inspection During 3R12:

The latest inspection of the IP3 RPV lower head was performed in April 2003, during refueling outage 3R12. This inspection consisted of a visual inspection performed by a VT-2 qualified individual, as well as engineering personnel, without insulation removal. The inspection included all 58 of the penetrations as well as the outside surface of the lower head insulation.

Several brown streaks were observed on the outside of the insulation, originating at the circumferential seam between the hemispherical section of the insulation and the cylindrical section of the insulation. Since this seam is located above all of the lower head penetrations, Entergy concluded that these streaks, did not initiate at any of the lower head penetrations.

In addition, brown streaks were observed in the vicinity of penetrations 1, 10, and 45 with no apparent corresponding streak path between the penetration and the circumferential insulation seam. Penetrations 1 and 10 are near the center of the reactor vessel and penetration 45 is near the periphery. Further assessment of this observation was accomplished by removing the metal ring and steel wool from penetration 45 to allow performing a Bare Metal Visual (BMV) examination of the penetration and the surrounding area of the head. Penetration 45 was selected for this examination since it was the most accessible of the three. Similarly, the insulation was removed and a BMV examination was performed for penetration 55 (located adjacent to 45) and the surrounding area of the head. These inspections confirmed that there was no evidence of leakage at the annulus around the penetrations inspected.

A chemical or isotopic analysis of the observed streaks was not practical because the streaks consisted primarily of staining, with little or no accumulated deposits available for sampling. There was no visual evidence of boron residue associated with any of the observed streaks.

The results of the inspection were documented in the procedure associated with this inspection activity and the assessment of the observed streaking was documented in Entergy's Corrective Action Program. Several photographs taken during the inspection were compared with photographs taken during previous inspections. This comparison indicated that the observed streaks appeared to be historical in nature and not the result of leakage occurring during the prior operating cycle. Based on a review of the observations, Entergy concluded that there was no evidence of pressure boundary leakage at the lower head.

Since the above inspection of the IP2 lower reactor vessel head identified no through-wall leakage it was determined that the integrity of the lower vessel head, including the Alloy 600 penetrations remained within the applicable ASME Code and other regulatory requirements identified in the Bulletin.

Compliance with Regulatory Requirements:

The basis for concluding that IP2 and IP3 satisfy the regulatory requirements applicable to the RPV lower head penetrations is the same as that previously stated in prior Bulletin responses regarding the RPV upper head penetrations. Also, the information provided in Section 3, Regulatory Requirements, of MRP-48 (Reference 1) is applicable for the IP2 and IP3 RPV lower head. Compliance with the applicable general design criteria (GDC 14, 31, and 32) is discussed in the Updated Final Safety Analysis Reports for IP2 and IP3. Entergy complies with the requirements of 10 CFR 50.55a through the Inservice Inspection Program and associated implementing procedures established for inspection and repair activities. The requirements of 10 CFR 50 Appendix B, Criteria V and IX involve documentation and control of special processes that are applicable to the existing inspections and new inspections being planned per the response to Item (1)(b). Compliance with these criteria is specified in Entergy's Quality Assurance Program document, which is applicable to IP2 and IP3. Criteria XIV requires measures to assure that conditions adverse to quality are promptly identified and corrected. Entergy has an established corrective action program, which includes provisions for identification and assessment of conditions adverse to quality.

Requested Information Item (1)(b):

A description of the RPV lower head penetration inspection program that will be implemented at your plant during the next and subsequent refueling outages. The description should include the extent of the inspections which will be conducted with respect to the areas and penetrations to be inspected, inspection methods to be used, qualification standards for the inspection methods, the process used to resolve the source of findings of boric acid deposits or corrosion, the inspection documentation to be generated, and the basis for concluding that your plant will satisfy applicable regulatory requirements related to the structural and leakage integrity of the RPV lower head penetrations.

Entergy Response:

The next refueling outages for IP2 and IP3 are scheduled for Fall 2004 and Spring 2005, respectively. Entergy is currently planning to perform a BMV inspection, 360 degrees around each of the 58 incore instrument nozzles at both units. Should unexpected obstructions or conditions be encountered during this effort, Entergy will implement the required changes to allow for a 100% BMV examination during the subsequent refueling outage, consistent with the requirements of this Bulletin. The BMV inspection would also apply to subsequent outages, unless industry experience or site-specific observations indicate the need for an alternate inspection approach.

As described in the response to item (1)(a), the area around each penetration is packed with steel wool covered by a metal cover that is screwed to the main insulation package. Entergy will remove the steel wool and metal covers from each of the 58 penetrations in order to gain access for a direct, unobstructed view of each incore instrument nozzle at the penetration through the RPV lower head. Remote visual devices may also be used to ensure a comprehensive inspection. The inspection procedures and inspector qualifications will be consistent with the requirements of ASME Section XI and EPRI recommendations (Reference 2) previously established for similar visual examinations of the RPV upper head. In addition, Entergy will monitor industry developments and inspections at other facilities through the existing operating experience program and will incorporate new information into the inspection plans, as appropriate.

Each of the 58 RPV lower head penetrations will be inspected for conditions that would be indicative of reactor coolant leakage from a through-wall defect in the incore instrument nozzle or in the J-Groove attachment weld that secures the instrument nozzle to the reactor vessel. Boron residue or other signs of leakage will be documented in Entergy's corrective action program and will be evaluated using the applicable ASME Section XI requirements. In the event that through-wall or other unacceptable defects are identified, repairs will be made in accordance with the requirements of 10 CFR 50.55(a), prior to restart from the refueling outage.

The process to be used to resolve findings will be similar to that previously established to support RPV upper head inspections, including use of industry-developed guidance (Reference 2). Operating experience from the South Texas examination will also be included if needed to assess findings from the inspection. Because of the physical configuration of the lower head, the potential for masking affects that can occur on the RPV upper head (such as conoseal leakage and material entrained by the ventilation system) will not be a factor for the RPV lower head inspection. Masking sources that could apply for the lower head inspection (refueling cavity seal or refueling cavity liner) occur at low temperature and tend to result in staining streaks on the insulation surface rather than accumulation of boron deposits. Chemical and / or radioisotopic analysis techniques may be used to help characterize the composition and source of deposits, if appropriate. The results of the inspections will be documented in accordance with the inspection procedures and resolution of findings, if any, will be documented through the Entergy corrective action program.

Compliance with Regulatory Requirements:

Adopting expanded inspection activities for the RPV lower head and penetrations does not adversely affect Entergy's compliance with applicable regulatory requirements. The response to item 1(a) regarding compliance with regulatory requirements is also applicable for the inspection program that will be implemented during the next and subsequent refueling outages. Conducting the planned BMV inspections, will provided additional assurance of reactor coolant pressure boundary integrity at the RPV lower head.

Requested Information Item (1)(c):

If you are unable to perform a bare-metal visual inspection of each penetration during the next refueling outage because of the inability to perform the necessary planning, engineering, procurement of materials, and implementation, are you planning to perform bare-metal visual inspections during subsequent refueling outages? If so, provide a description of the actions that *are planned to enable a bare-metal visual inspection of each penetration during subsequent refueling outages. Also, provide a description of any penetration inspections you plan to perform during the next refueling outage. The description should address the applicable items in paragraph (b).*

Entergy Response:

Entergy intends to perform a BMV inspection of each penetration in the RPV lower head during the next refueling outages for IP2 and IP3. However, as stated in the response to item 1(b), if unexpected obstructions or conditions interfere with completing the full inspection at that time, as planned, other actions may be taken to allow for the BMV inspection to be performed at the subsequent refueling outage. In the event that this situation develops, a discussion of the circumstances and updated inspection strategy will be included in the inspection results report discussed in Requested Information Item (2).

Requested Information Item (1)(d):

If you do not plan to perform either a bare-metal visual inspection or non-visual (e.g., volumetric or surface) examination of the RPV lower head penetrations at the next or subsequent refueling outages, provide the basis for concluding that the inspections performed will assure applicable regulatory requirements are and will continue to be met.

Entergy Response:

Entergy intends to perform a BMV inspection of the RPV lower head penetrations during the next refueling outage for each unit. Therefore the basis for ensuring that applicable regulatory requirements are and will continue to be met includes the performance of these inspections. In the event that inspections cannot be performed as planned Entergy will reassess the basis for concluding that applicable regulatory requirements are met, and document this reassessment in the inspection results report discussed in Requested Information Item (2).

Requested Information Item (2):

Within 60 days of plant restart following the next inspection of the RPV lower head penetrations, the subject PWR addressees should submit to the NRC a summary of the inspections performed, the extent of the inspections, the methods used, a description of the as-found condition of the lower head, any findings of relevant indications of through-wall leakage, and a summary of the disposition of any findings of boric acid deposits and any corrective actions taken as a result of indications found.

Entergy Response:

Entergy agrees to submit the requested information within 60 days of restart following the next inspection of the RPV lower head penetrations. These inspections are currently planned for the next refueling outages as discussed in the response to item (1)(b).

References:

1. EPRI Report MRP-48, "PWR Materials Reliability Program Response to NRC Bulletin 2001-01", August 2001.

2. EPRI Report 1006296, "Visual Examination for Leakage of PWR Reactor Head Penetrations on Top of RPV Head", Revision 1 dated March 2002. (or later version as needed)

OMB Control No.: 3150-0012

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, DC 20555

August 21, 2003

NRC BULLETIN 2003-02: LEAKAGE FROM REACTOR PRESSURE VESSEL LOWER HEAD PENETRATIONS AND REACTOR COOLANT PRESSURE BOUNDARY INTEGRITY

Addressees

All holders of operating licenses for pressurized-water nuclear power reactors (PWRs) with penetrations in the lower head of the reactor pressure vessel (RPV), except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor pressure vessel.

All other holders of operating licenses for nuclear power plants will receive a copy of this bulletin for information.

Purpose

The U.S. Nuclear Regulatory Commission (NRC) is issuing this bulletin to:

(1) advise PWR addressees that current methods of inspecting the RPV lower heads may need to be supplemented with additional measures (e.g., bare-metal visual inspections) to detect reactor coolant pressure boundary (RCPB) leakage,

(2) request PWR addressees to provide the NRC with information related to inspections that have been or will be performed to verify the integrity of the RPV lower head penetrations, and

(3) require PWR addresses to provide a written response to the NRC in accordance with the provisions of Section 50.54(f) of Title 10 of the *Code of Federal Regulations* (10 CFR 50.54(f)).

Background

PWR RPV upper heads have a number of penetrations, including penetrations for control rod drive mechanisms (CRDMs). These penetrations are typically made of nickel-based Inconel Alloy 600. The penetrations are welded to the inside of the RPV head with nickel-based Inconel Alloy 82/182 materials. Most PWRs also have penetrations in the RPV lower heads for in-core nuclear instrumentation. The same Inconel materials are typically used in the lower head penetrations and welds. The primary coolant water and the operating conditions of PWR plants have caused cracking of nickel-based alloys in upper head penetrations through a process called primary water stress corrosion cracking (PWSCC).

As part of the response to issues associated with degradation of the RPV upper head at the Davis-Besse Nuclear Power Station, the NRC issued Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," dated March 18, 2002. This bulletin requested information about the condition and inspections of RPV upper heads and about licensee's boric acid corrosion control (BACC) programs. The NRC subsequently issued Bulletin 2002-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs," dated August 9, 2002. This bulletin was issued to address staff concerns regarding the adequacy of visual examinations as a primary inspection method for the RPV upper head and RPV upper head penetrations. By NRC Order EA-03-009, dated February 11, 2003, the NRC required specific inspections of RPV upper heads, CRDM penetrations, and associated welds in addition to the inspections required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Code).

After evaluating the responses received in response to Bulletin 2002-01, the NRC staff issued requests for additional information (RAIs) to PWR licensees in order to obtain more detailed information regarding licensee BACC programs. The NRC staff summarized its review of the responses to Bulletin 2002-01 and the associated RAIs in Regulatory Issue Summary (RIS) 2003-13, "NRC Review of Responses to Bulletin 2002-01, 'Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,'" dated July 29, 2003. The NRC noted in RIS 2003-13 that most licensees do not perform inspections of Alloy 600/82/182 materials beyond those required by Section XI of the ASME Code to identify potential cracked and leaking components. For the RPV lower head, the ASME Code specifies that a visual examination, called a VT-2 examination, be performed during system pressure testing. Licensees may meet the ASME Code requirement for a VT-2 inspection by performing an inspection of the RPV lower head without removing insulation from around the head and penetrations. It is the NRC staff's understanding that many licensees perform the ASME Code-required inspections without removing insulation and, therefore, may not be able to detect the amounts of through-wall leakage expected from potential flaws due to PWSCC or other cracking mechanisms.

The lower head and bottom mounted instrumentation (BMI) penetrations of the South Texas Project Unit 1 (STP Unit 1) RPV were visually inspected on April 12, 2003, as a routine part of the unit's refueling outage. The lower head of the reactor is surrounded by an insulating box structure with no insulation directly in contact with the lower head. The inspection was accomplished by removing three of the insulation panels forming the insulating box. Three different vantage points were used to inspect all 58 BMI penetrations in the vessel lower head. The inspection found small amounts of white residue around two of the 58 BMI penetrations (numbers 1 and 46) at the junction where the penetrations met the lower reactor vessel head. The residue at penetrations 1 and 46 was collected for laboratory analysis to determine the source of the residue material. Approximately 150 milligrams and 3 milligrams were collected from penetrations 1 and 46, respectively. The analysis of the sample for lithium demonstrated that the lithium was approximately 99.9 percent lithium-7, which indicated that the reactor coolant system was the source of the residue. The analysis of the sample for cesium indicated that the average age of the residue collected was between 3 and 5 years. The licensee for STP Unit 1 indicated that these residues were not visible during the previous inspection on November 20, 2002.

Ultrasonic inspections (using circumferential, axial, and zero degree probes) of 57 BMI penetration tubes at STP Unit 1 were completed in May 2003, along with the visual inspections of the surfaces of the 58 J-groove welds which attach the BMI penetration tubes to the RPV lower head. In addition, eddy current testing (ECT) was used to examine the J-groove weld and inside diameter surfaces of some BMI penetration tubes. Axial cracks were found in penetration tubes 1 and 46. The largest of these cracks was entirely through-wall and extended above and below the J-groove weld. No evidence of cracking was found in any other penetration. BMI penetrations 1 and 46 have been repaired. The licensee is continuing to investigate the cause of the cracks. The investigation has not, to date, identified any manufacturing practice or operating condition that is unique to the affected penetrations or to the RPV at STP Unit 1. The design of the area beneath the RPV at STP Unit 1 and the inspection methods used by the licensee enabled the discovery of the leaking penetrations. From the NRC staff reviews described in RIS 2003-13, the NRC staff concluded that leakage such as that observed at STP Unit 1 would likely not have been detected during inspections performed at many other PWRs.

Discussion

The RPV and its head penetrations are an integral part of the RCPB, and their integrity is important to the safe operation of the plant. The recent identification of cracking and leakage from two BMI penetrations at STP Unit 1 raises questions about potential degradation mechanisms which may be active in this area. In addition, licensee responses to the Bulletin 2002-01 followup RAIs raised questions about the adequacy of inspections performed by licensees to detect leakage from RPV lower head penetrations.

As indicated above, the investigation of the degradation mechanism involved in the cracking of the two penetrations at STP Unit 1 is continuing. However, an evaluation of the available information leads to several observations. First, although the root cause of the cracking experienced at STP Unit 1 is not yet understood, the investigation to date has not identified potential root causes which would be unique to the affected penetrations at STP Unit 1.

Second, the licensee for STP Unit 1 uses a method of inspecting the RPV lower head penetrations that permits visual examination of the external metal surfaces of the vessel lower head and its penetrations, unimpeded by the surrounding insulation. In comparison to the previously discussed VT-2 examinations specified in Section XI of the ASME Code, which do not require the removal of insulation and must be performed at normal operating pressure conditions once each refueling outage, the inspections conducted by the STP Unit 1 licensee are superior for the purpose of finding evidence of leakage like that observed at STP Unit 1. In fact, the NRC staff has concluded that the VT-2 examinations required by Section XI of the ASME Code would not be effective at finding deposits like those discovered at STP Unit 1.

Third, the circumstances of the STP Unit 1 findings indicate that the cracking and the onset of leakage may have occurred several years prior to the discovery of leakage. The licensee's prior inspections of STP Unit 1 lower head were capable of finding the deposits observed in April 2003. However, no evidence of leakage had been noted as the result of any inspections conducted prior to April 2003. Therefore, a one-time inspection of an RPV lower head area may not provide adequate assurance that degradation is not occurring similar to that observed in the BMI penetrations at STP Unit 1.

The small amount of leakage from the cracks discovered at STP Unit 1 did not represent an immediate safety problem due to the size and orientation of the cracks. In addition, safety systems included in plant designs and required to be available during plant operation would be able to mitigate the effects of more significant leaks, including a gross rupture of an RPV lower head penetration. Although unlikely, a significant leak from an RPV lower head penetration could introduce operational and safety concerns since it would require operation of safety systems for an extended period and complicate longer term efforts to stabilize the plant. To maintain the overall defense-in-depth philosophy incorporated into the design and operation of nuclear power plants, licensees should take appropriate actions to ensure the integrity of the RPV lower head penetrations.

The NRC staff believes it is appropriate for licensees to assess their current inspection practices to periodically ensure that there are no leaks from RPV lower head penetrations. This conclusion is based on the safety concerns associated with a significant leak from the RPV lower head and the uncertainties associated with the ability of some current inspection practices to identify cracks and resultant small leaks from RPV lower head penetrations.

Inspections capable of detecting through-wall leakage from any RPV lower head penetration, beginning at the next refueling outage, would provide additional confidence in the integrity of the RPV lower head penetrations. If visual inspections are performed to detect evidence of possible leakage, such inspections should include an inspection of 100% of the circumference of each penetration as it enters the RPV lower head.

The industry's Materials Reliability Program (MRP) has made recommendations for PWR licensees to perform bare-metal visual inspections of RPV lower head penetrations during the current or next refueling outage. The recommendations were included in a letter from Leslie Hartz, MRP Senior Representative, dated June 23, 2003 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML031920395). The MRP is an industry program, coordinated by EPRI, to address material-related issues associated with PWRs.

The NRC is aware that preexisting conditions at some facilities may prevent licensees from performing bare-metal visual inspections of some RPV lower head penetrations during their next refueling outage. For these plants, such inspections of the RPV lower head penetrations may not be possible, for example, until after plant modifications, cleaning, and completion of other tasks provide access and a clean surface for baseline and future inspections. For the plants unable to perform inspections as recommended above, additional confidence in the integrity of the RPV lower head penetrations may be obtained by licensees (1) developing an inspection plan to examine as many of the RPV lower head penetrations as is practical, and (2) taking the necessary steps to enable the performance of inspections as above for each penetration during subsequent refueling outages. In conducting inspections or other activities on the RPV lower head, licensees should recognize that entry into and work in cavities under PWR reactor vessels present very high radiation hazards. Access controls to these areas should require, among other things, close communication between plant operations and radiation protection staff on the status of the highly activated components (e.g., thimble retraction from the core into the reactor cavity) so that required reactor cavity access controls and oversight can be fully implemented before very high radiation levels are created. More information on these under-vessel hazards is provided in Appendix B of Regulatory Guide 8.38, "Control Of Access To High And Very High Radiation Areas In Nuclear Power Plants."

The NRC staff is working with the industry and other stakeholders to revise the ASME Code and NRC regulations to address inspection of RCPB locations susceptible to cracking, including RPV penetrations. These activities will not be completed for several years, so the NRC is issuing this bulletin to address the immediate concerns identified following the reviews of the responses to Bulletin 2002-01 and followup RAIs and the discovery of leaks from BMI penetrations at STP Unit 1. The NRC has posted and will continue to post information about these subjects on its Web site (www.nrc.gov).

Applicable Regulatory Requirements

The NRC has acknowledged that the existing regulatory requirements may need to be supplemented in order to ensure required inspections of RPV lower head penetrations are adequate to identify potential penetration leakage. However, several provisions of the NRC regulations and plant operating licenses (technical specifications) pertain to RCPB integrity and the issues addressed by this bulletin. The general design criteria (GDC) for nuclear power plants (Appendix A to 10 CFR Part 50), or, as appropriate, similar requirements in the licensing basis for a reactor facility, the requirements of 10 CFR 50.55a, and the quality assurance criteria of Appendix B to 10 CFR Part 50 provide the bases and requirements for NRC staff assessment of the potential for, and consequences of, degradation of the RCPB.

The applicable GDCs include GDC 14 (Reactor Coolant Pressure Boundary), GDC 31 (Fracture Prevention of Reactor Coolant Pressure Boundary), and GDC 32 (Inspection of Reactor Coolant Pressure Boundary). GDC 14 specifies that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture. GDC 31 specifies that the probability of rapidly propagating fracture of the RCPB be minimized. GDC 32 specifies that components which are part of the RCPB have the capability of being periodically inspected to assess their structural and leaktight integrity.

NRC regulations in 10 CFR 50.55a state that ASME Class 1 components (which includes the RCPB) must meet the requirements of Section XI of the ASME Code. Various portions of the ASME Code address RCPB inspection. For example, Table IWB-2500-1 of Section XI of the ASME Code provides examination requirements during system leakage testing of all pressure-retaining components of the RCPB and references IWB-3522 for acceptance standards. IWB-3522.1(c) and (e) specify that conditions requiring correction include the detection of leakage from insulated components and discoloration or accumulated residues on the surfaces of components, insulation, or floor areas that may be evidence of borated water leakage, with leakage defined as the through-wall leakage that penetrates the pressure retaining membrane. Therefore, 10 CFR 50.55a, by reference to the ASME Code, does not permit through-wall degradation of the RPV lower head penetrations. For through-wall leakage identified by visual examinations in accordance with the ASME Code, acceptance standards for the identified degradation are provided in IWB-3142. Specifically, supplemental examination (by surface or volumetric examination), corrective measures or repairs, analytical evaluation, and replacement provide methods for determining the acceptability of degraded components. Criterion V (Instructions, Procedures, and Drawings) of Appendix B to 10 CFR Part 50 states that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Criterion V further states that instructions, procedures, or drawings shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Visual and volumetric examinations of the RCPB are activities that should be documented in accordance with these requirements.

Criterion IX (Control of Special Processes) of Appendix B to 10 CFR Part 50 states that special processes, including nondestructive testing, shall be controlled and accomplished by qualified personnel using qualified procedures in accordance with applicable codes, standards, specifications, criteria, and other special requirements.

Criterion XVI (Corrective Action) of Appendix B to 10 CFR Part 50 states that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. For significant conditions adverse to quality, the measures taken shall include root cause determination and corrective action to preclude repetition of the adverse conditions. For degradation of the RCPB, the root cause determination is important for understanding the nature of the degradation present and the required actions to mitigate future degradation. These actions could include proactive inspections and repair of degraded portions of the RCPB.

Plant technical specifications (TS) pertain to this issue insofar as they do not allow operation with through-wall reactor coolant system pressure boundary leakage.

Requested Information

(1) All subject PWR addressees are requested to provide the following information. The responses for facilities that will enter refueling outages before December 31, 2003, should be provided within 30 days of the date of this bulletin. All other responses should be provided within 90 days of the date of this bulletin.

(a) A description of the RPV lower head penetration inspection program that has been implemented at your plant. The description should include when the inspections were performed, the extent of the inspections with respect to the areas and penetrations inspected, inspection methods used, the process used to resolve the source of findings of any boric acid deposits, the quality of the documentation of the inspections (e.g., written report, video record, photographs), and the basis for concluding that your plant satisfies applicable regulatory requirements related to the integrity of the RPV lower head penetrations.

(b) A description of the RPV lower head penetration inspection program that will be implemented at your plant during the next and subsequent refueling outages. The description should include the extent of the inspections which will be conducted with respect to the areas and penetrations to be inspected, inspection methods to be used, qualification standards for the inspection methods, the process used to resolve the source of findings of boric acid deposits or corrosion, the inspection documentation to be generated, and the basis for concluding that your plant will satisfy applicable regulatory requirements related to the structural and leakage integrity of the RPV lower head penetrations.

(c) If you are unable to perform a bare-metal visual inspection of each penetration during the next refueling outage because of the inability to perform the necessary planning, engineering, procurement of materials, and implementation, are you planning to perform bare-metal visual inspections during subsequent refueling outages? If so, provide a description of the actions that are planned to enable a bare-metal visual inspection of each penetration during subsequent refueling outages. Also, provide a description of any penetration inspections you plan to perform during the next refueling outage. The description should address the applicable items in paragraph (b).

(d) If you do not plan to perform either a bare-metal visual inspection or non-visual (e.g., volumetric or surface) examination of the RPV lower head penetrations at the next or subsequent refueling outages, provide the basis for concluding that the inspections performed will assure applicable regulatory requirements are and will continue to be met.

(2) Within 60 days of plant restart following the next inspection of the RPV lower head penetrations, the subject PWR addressees should submit to the NRC a summary of the inspections performed, the extent of the inspections, the methods used, a description of the as-found condition of the lower head, any findings of relevant indications of through-wall leakage, and a summary of the disposition of any findings of boric acid deposits and any corrective actions taken as a result of indications found.

Required Response

In accordance with 10 CFR 50.54(f), the subject PWR addressees are required to submit written responses to this bulletin. This information is sought to verify licensees' compliance with the current licensing basis for the subject PWR addressees. The addressees have two options:

(1) addressees may choose to submit written responses providing the information requested above within the requested time periods, or

(2) addressees who choose not to provide the information requested or cannot meet the requested completion dates are required to submit written responses within 15 days of the date of this bulletin. The responses must address any alternative course of action proposed, including the basis for the acceptability of the proposed alternative course of action.

The required written responses should be addressed to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, 11555 Rockville Pike, Rockville, Maryland 20852, under oath or affirmation under the provisions of Section 182a of the Atomic Energy Act of 1954, as amended, and 10 CFR 50.54(f). In addition, a copy of a response should be submitted to the appropriate regional administrator.

Reasons for Information Request

NRC regulatory requirements and plant TS requirements preclude operation with through-wall leakage from the RCPB. Requirements in the ASME Code, NRC regulations, and plant TS are intended to make licensees perform inspections to maintain an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture. The current inspection techniques used at many PWRs may not detect small leaks such as those discovered at STP Unit 1. Uncertainty exists about the root cause of the cracking and resultant leakage at STP Unit 1, and whether other PWRs with RPV lower head penetrations could have similar problems. A detailed assessment of the risks associated with this issue is hampered by the uncertainties associated with the degradation mechanisms which may be active in RPV lower head penetrations, plant conditions (especially for those plants that have not performed the recommended inspections), and the course of events given a significant leak from the lower head. Improved inspections of the RPV lower head penetrations will resolve some of these uncertainties and could identify and allow correction of conditions before they become a significant safety concern.

This information request is necessary to permit the NRC staff to verify compliance with existing regulations and plant-specific licensing bases. The information being requested by this bulletin focuses on RPV lower head penetrations in more detail than previous generic communications and, therefore, is not currently available to the NRC staff. The NRC staff will use the information to assess the acceptability of current licensee lower vessel head inspection programs to identify BMI penetration leakage, and to determine the need for, and guide the development of, any additional regulatory actions (e.g., generic communications, orders, or rulemaking) to address the integrity of the RCPB. Such regulatory actions could include regulatory requirements for augmented inspection programs under 10 CFR 50.55a(g)(6)(ii). The NRC staff will review the responses to this bulletin to determine whether the PWR addressees' inspections provide reasonable assurance that existing applicable regulations are met. If concerns are identified, the NRC staff will contact each affected addressee.

<u>Related Generic Communications</u>

Regulatory Issue Summary 2003-13, "NRC Review of Responses to Bulletin 2002-01, 'Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,' July 29, 2003 (ADAMS Accession No. ML032100653)

Information Notice 2003-11 "Leakage Found on Bottom-Mounted Instrumentation Nozzles," August 13, 2003 (ADAMS Accession No. ML032250135)

Bulletin 2002-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs," August 9, 2002 (ADAMS Accession No. ML022200494)

Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," March 18, 2002 (ADAMS Accession No. ML020770497)

Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," March 17, 1988 (ADAMS Accession No. ML031130424)

<u>Backfit Discussion</u>

Under the provisions of Section 182a of the Atomic Energy Act of 1954, as amended, and 10 CFR 50.54(f), this bulletin transmits an information request for the purpose of verifying compliance with existing applicable regulatory requirements (see the Applicable Regulatory Requirements section of this bulletin). Specifically, the required information will enable the NRC staff to determine whether current inspection and maintenance practices for the detection of degradation of the RCPB at reactor facilities (similar to the degradation observed at STP

Unit 1) provide reasonable assurance that RCPB integrity is being maintained. No backfit is either intended or approved by the issuance of this bulletin, and the staff has not performed a backfit analysis.

Federal Register Notification

A notice of opportunity for public comment on this bulletin was not published in the *Federal Register* because the NRC staff is requesting information from power reactor licensees on an expedited basis for the purpose of assessing compliance with existing applicable regulatory requirements and the need for subsequent regulatory action. This bulletin was prompted by the discovery of leaks from BMI penetrations at STP Unit 1 and by the NRC staff's assessment of responses to Bulletin 2002-01. As the resolution of this matter progresses, the opportunity for public involvement will be provided. Nevertheless, comments on the actions requested and the technical issues addressed by this bulletin may be sent to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001.

Small Business Regulatory Enforcement Fairness Act

The NRC has determined that this action is not subject to the Small Business Regulatory Enforcement Fairness Act of 1996.

Paperwork Reduction Act Statement

This bulletin contains an information collection that is subject to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 et seq.). This information collection was approved by the Office of Management and Budget, clearance no. 3150-0012, which expires August 31, 2006. The burden to the public for this mandatory information collection is estimated to average 110 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the information collection. Send comments regarding this burden estimate or any other aspect of this information collection, including suggestions for reducing the burden, to the Records Management Branch (T-6 E6), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by Internet electronic mail to INFOCOLLECTS@NRC.GOV; and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202, (3150-0012), Office of Management and Budget, Washington, DC 20503.

Public Protection Notification

The NRC may not conduct or sponsor, and a person is not required to respond to, an information collection unless the requesting document displays a currently valid OMB control number.

If you have any questions about this matter, please contact one of the persons listed below or the appropriate Office of Nuclear Reactor Regulation project manager.

/RA/
Bruce A. Boger, Director
Division of Inspection Program Management
Office of Nuclear Reactor Regulation

Technical Contact: Edmund Sullivan
301-415-2796
E-mail: ejs@nrc.gov

Lead Project Manager: Stephen R. Monarque
301-415-1544
E-mail: srm2@nrc.gov

Exhibit Y

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d)	Section 3.4.3, Rev. 0 9 pages	d)	Section 3.4.3, Rev. 1 9 pages
e)	Section 3.4.12, Rev. 0 20 pages	e)	Section 3.4.12, Rev. 1 20 pages
f)	Section B 3.5.1; Rev. 0 10 pages	f)	Section B 3.5.1; Rev. 1 10 pages

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B 3.4.15	2	7	11/19/2001
B 3.4.16	0	7	03/19/2001
B 3.5 ECCS			
B 3.5.1	**1**	**10**	**10/27/2004**
B 3.5.2	0	13	03/19/2001
B 3.5.3	0	4	03/19/2001
B 3.5.4	0	9	03/19/2001

BASES SECTION	REV	NUMBER OF PAGES	EFFECTIVE DATE
B 3.6 CONTAINMENT			
B 3.6.1	0	5	03/19/2001
B 3.6.2	0	9	03/19/2001
B 3.6.3	0	17	03/19/2001
B 3.6.4	0	3	03/19/2001
B 3.6.5	1	5	06/20/2003
B 3.6.6	1	13	12/04/2002
B 3.6.7	0	6	03/19/2001
B 3.6.8	0	6	03/19/2001
B 3.6.9	0	8	03/19/2001
B 3.6.10	0	12	03/19/2001
B 3.7 PLANT SYSTEMS			
B 3.7.1	1	6	12/04/2002
B 3.7.2	0	10	03/19/2001
B 3.7.3	1	7	05/18/2001
B 3.7.4	0	5	03/19/2001
B 3.7.5	0	11	03/19/2001
B 3.7.6	1	4	12/04/2002
B 3.7.7	0	4	03/19/2001
B 3.7.8	0	7	03/19/2001
B 3.7.9	1	9	09/30/2002
B 3.7.10	0	3	03/19/2001
B 3.7.11	2	9	06/20/2003
B 3.7.12	0	4	03/19/2001
B 3.7.13	2	7	06/20/2003
B 3.7.14	0	3	03/19/2001
B 3.7.15	0	5	03/19/2001
B 3.7.16	0	6	03/19/2001
B 3.7.17	0	4	03/19/2001
B 3.8 ELECTRICAL POWER			
B 3.8.1	1	32	01/22/2002
B 3.8.2	0	7	03/19/2001
B 3.8.3	0	13	03/19/2001
B 3.8.4	1	11	01/22/2002
B 3.8.5	0	4	03/19/2001
B 3.8.6	0	8	03/19/2001
B 3.8.7	1	8	06/20/2003
B 3.8.8	1	4	06/20/2003
B 3.8.9	2	14	06/20/2003
B 3.8.10	0	4	03/19/2001
B 3.9 REFUELING OPERATIONS			
B 3.9.1	0	4	03/19/2001
B 3.9.2	0	4	03/19/2001
B 3.9.3	1	8	03/17/2003
B 3.9.4	0	4	03/19/2001
B 3.9.5	0	4	03/19/2001
B 3.9.6	0	4	03/19/2001

REVISION HISTORY FOR BASES

AFFECTED SECTIONS	REV	EFFECTIVE DATE	DESCRIPTION
ALL	0	03/19/01	Initial issue of Bases derived from NUREG-1431, in conjunction with Technical Specification Amendment 205 for conversion of 'Current Technical Specifications' to 'Improved Technical Specifications'.
BASES UPDATE PACKAGE 01-031901			
B 3.4.13 B 3.4.15	1	03/19/01	Changes regarding containment sump flow monitor per NSE 01-3-018 LWD Rev 0. Change issued concurrent with Rev 0.
BASES UPDATE PACKAGE 02-051801			
Table of Contents	1	05/18/01	Title of Section B 3.7.3 revised per Tech Spec Amend 207
B 3.7.3	1	05/18/01	Implementation of Tech Spec Amend 207
BASES UPDATE PACKAGE 03-111901			
B 3.3.2	1	11/19/01	Correction to statement regarding applicability of Function 5, to be consistent with the Technical Specification.
B 3.3.3	1	11/19/01	Changes to reflect reclassification of certain SG narrow range level instruments as QA Category M per NSE 97-3-439, Rev 1.
B 3.4.13 B 3.4.15	2	11/19/01	Changes to reflect installation of a new control room alarm for 'VC Sump Pump Running'. Changes per NSE 01-3-018, Rev 1 and DCP 01-3-023 LWD.
B 3.7.11	1	11/19/01	Clarification of allowable flowrate for CRVS in 'incident mode with outside air makeup.'
BASES UPDATE PACKAGE 04-012202			
B 3.3.2	2	01/22/02	Clarify starting logic of 32 ABFP per EVL-01-3-078 MULTI, Rev 0.
B 3.8.1	1	01/22/02	Provide additional guidance for SR 3.8.1.1 and Condition Statements A.1 and B.1 per EVL-01-3-078 MULTI, Rev 0.
B 3.8.4	1	01/22/02	Revision of battery design description per plant modification and to reflect Tech Spec Amendment 209.
B 3.8.9	1	01/22/02	Provide additional information regarding MCC in Table B 3.8.9-1 per EVL-01-3-078 MULTI, Rev 0.
BASES UPDATE PACKAGE 05-093002			
B 3.0	1	09/30/02	Changes to reflect Tech Spec Amendment 212 regarding delay period for a missed surveillance. Changes adopt TSTF 358, Rev 6.
B 3.3.1	1	09/30/02	Changes regarding description of turbine runback feature per EVAL-99-3-063 NIS.
B 3.3.3	2	09/30/02	Changes to reflect Tech Spec Amendment 211 regarding CETs and other PAM instruments.
B 3.7.9	1	09/30/02	Changes regarding SWN -35-1 and -2 valves per EVAL-00-3-095 SWS, Rev 0.

TECHNICAL SPECIFICATION BASES
REVISION HISTORY

AFFECTED SECTIONS	REV	EFFECTIVE DATE	DESCRIPTION
BASES UPDATE PACKAGE 06-120402			
B 3.3.2 B 3.6.6 B 3.7.1 B 3.7.6	3 1 1 1	12/04/02	Changes to reflect Tech Spec Amendment 213 regarding 1.4% power uprate.
BASES UPDATE PACKAGE 07-031703			
B 3.3.8 B 3.7.13 B 3.9.3	1 1 1	03/17/2003	Changes to reflect Tech Spec Amendment 215 regarding implementation of Alternate Source Term analysis methodology to the Fuel Handling Accident
BASES UPDATE PACKAGE 08-032803			
B 3.4.9	1	03/28/2003	Changes to reflect Tech Spec Amendment 216 regarding relaxation of pressurizer level limits in MODE 3.
BASES UPDATE PACKAGE 09-062003			
B 3.4.9	2	06/20/2003	Changes to reflect commitment for a dedicated operator per Tech Spec Amendment 216.
B 3.6.5	1	06/20/2003	Implements Corrective Action 11 from CR-IP3-2002-02095; 4 FCUs should be in operation to assure representative measurement of containment air temperature.
B 3.7.11	2	06/20/2003	Correction to Background description regarding system response to Firestat detector actuation per ACT 02-62887.
B 3.7.13	2	06/20/2003	Revision to Background description of FSB air tempering units to reflect design change per DCP 95-3-142.
B 3.8.7 B 3.8.8 B 3.8.9	1 1 2	06/20/2003 06/20/2003 06/20/2003	Changes to reflect replacement of Inverter 34 per DCP-01-022.
BASES UPDATE PACKAGE 10-102704			
B 3.1.3	1	10/27/2004	Clarification of the surveillance requirements for TS 3.1.3 per 50.59 screen.
B 3.3.5	1	10/27/2004	Clarify the requirements for performing a Trip Actuating Device Operational Test (TADOT) on the 480V degraded grid and undervoltage relays per 50.59 screen.
B 3.4.3 B 3.4.12	1 1	10/27/2004	Extension of the RCS pressure/temperature limits and corresponding OPS limits from 16.17 to 20 EFPY (TS Amendment 220).
B 3.5.1	1	10/27/2004	Changes to reflect Tech Spec Amendment 222 regarding extension of completion time for Accumulators.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Moderator Temperature Coefficient (MTC)

BASES

BACKGROUND

According to GDC 11 (Ref. 1), the reactor core and its interaction with the Reactor Coolant System (RCS) must be designed for inherently stable power operation, even in the possible event of an accident. In particular, the net reactivity feedback in the system must compensate for any unintended reactivity increases.

The MTC relates a change in core reactivity to a change in reactor coolant temperature (a positive MTC means that reactivity increases with increasing moderator temperature; conversely, a negative MTC means that reactivity decreases with increasing moderator temperature). The reactor is designed to operate with a negative MTC over the largest possible range of fuel cycle operation. Therefore, a coolant temperature increase will cause a reactivity decrease, so that the coolant temperature tends to return toward its initial value. Reactivity increases that cause a coolant temperature increase will thus be self limiting, and stable power operation will result.

MTC values are predicted at selected burnups during the safety evaluation analysis and are confirmed to be acceptable by measurements. Both initial and reload cores are designed so that the beginning of life (BOL) MTC is less than zero when THERMAL POWER is at RTP. The actual value of the MTC is dependent on core characteristics, such as fuel loading and reactor coolant soluble boron concentration. The core design may require additional fixed distributed poisons to yield an MTC at BOL within the range analyzed in the plant accident analysis. The end of life (EOL) MTC is also limited by the requirements of the accident analysis. Fuel cycles that are designed to achieve high burnups or that have changes to other characteristics are evaluated to ensure that the MTC does not exceed the EOL limit.

The limitations on MTC are provided to ensure that the value of this coefficient remains within the limiting conditions assumed in the FSAR accident and transient analyses.

(continued)

BASES

BACKGROUND (continued)

If the LCO limits are not met, the unit response during transients may not be as predicted. The core could violate criteria that prohibit a return to criticality, or the departure from nucleate boiling ratio criteria of the approved correlation may be violated, which could lead to a loss of the fuel cladding integrity.

The SRs for measurement of the MTC at the beginning and near the end of the fuel cycle are adequate to confirm that the MTC remains within its limits, since this coefficient changes slowly, due principally to the reduction in RCS boron concentration associated with fuel burnup.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for the specified MTC are:

a. The MTC values must remain within the bounds of those used in the accident analysis (Ref. 2); and

b. The MTC must be such that inherently stable power operations result during normal operation and accidents, such as overheating and overcooling events.

The FSAR, Chapter 14 (Ref. 2), contains analyses of accidents that result in both overheating and overcooling of the reactor core. MTC is one of the controlling parameters for core reactivity in these accidents. Both the most positive value and most negative value of the MTC are important to safety, and both values must be bounded. Values used in the analyses consider worst case conditions to ensure that the accident results are bounding (Ref. 3).

The consequences of accidents that cause core overheating must be evaluated when the MTC is positive. Such accidents include the rod withdrawal transient from either zero (Ref. 2) or RTP, loss of main feedwater flow, and loss of forced reactor coolant flow.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The consequences of accidents that cause core overcooling must be evaluated when the MTC is negative. Such accidents include sudden feedwater flow increase and sudden decrease in feedwater temperature.

In order to ensure a bounding accident analysis, the MTC is assumed to be its most limiting value for the analysis conditions appropriate to each accident. The bounding value is determined by considering rodded and unrodded conditions, whether the reactor is at full or zero power, and whether it is the BOL or EOL. The most conservative combination appropriate to the accident is then used for the analysis (Ref. 2).

MTC values are bounded in reload safety evaluations assuming steady state conditions at BOL and EOL. An EOL measurement is conducted at conditions when the RCS boron concentration reaches approximately 300 ppm. The measured value may be extrapolated to project the EOL value, in order to confirm reload design predictions.

MTC satisfies Criterion 2 of 10 CFR 50.36. Even though it is not directly observed and controlled from the control room, MTC is considered an initial condition process variable because of its dependence on boron concentration.

LCO

LCO 3.1.3 requires the MTC to be within specified limits of the COLR to ensure that the core operates within the assumptions of the accident analysis. During the reload core safety evaluation, the MTC is analyzed to determine that its values remain within the bounds of the original accident analysis during operation.

Assumptions made in safety analyses require that the MTC be less positive than a given upper bound and more positive than a given lower bound. The MTC is most positive near BOL; this upper bound must not be exceeded. This maximum upper limit occurs at BOL, all rods out (ARO), hot zero power conditions.

(continued)

BASES

LCO (continued)

At EOL the MTC takes on its most negative value, when the lower bound becomes important. This LCO exists to ensure that both the upper and lower bounds are not exceeded.

During operation, therefore, the conditions of the LCO can only be ensured through measurement. The Surveillance checks at BOL and EOL on MTC provide confirmation that the MTC is behaving as anticipated so that the acceptance criteria are met.

The LCO establishes a maximum positive value that cannot be exceeded. The BOL positive limit and the EOL negative limit are established in the COLR to allow specifying limits for each particular cycle. This permits the unit to take advantage of improved fuel management and changes in unit operating schedule.

APPLICABILITY

Technical Specifications place both LCO and SR values on MTC, based on the safety analysis assumptions described above.

In MODE 1, the limits on MTC must be maintained to ensure that any accident initiated from THERMAL POWER operation will not violate the design assumptions of the accident analysis. In MODE 2 with the reactor critical, the upper limit must also be maintained to ensure that startup and subcritical accidents (such as the uncontrolled CONTROL ROD assembly or group withdrawal) will not violate the assumptions of the accident analysis. The lower MTC limit must be maintained in MODES 2 and 3, in addition to MODE 1, to ensure that cooldown accidents will not violate the assumptions of the accident analysis. In MODES 4, 5, and 6, this LCO is not applicable, since no Design Basis Accidents using the MTC as an analysis assumption are initiated from these MODES.

ACTIONS

A.1

If the BOL MTC limit is violated, administrative withdrawal limits for control banks must be established to maintain the MTC within its limits. The MTC becomes more negative with control bank insertion and decreased boron concentration. A Completion Time of 24 hours provides enough time for evaluating the MTC measurement and computing the required bank withdrawal limits.

(continued)

BASES

ACTIONS

A.1 (continued)

As cycle burnup is increased, the RCS boron concentration will be reduced. The reduced boron concentration causes the MTC to become more negative. Using physics calculations, the time in cycle life at which the calculated MTC will meet the LCO requirement can be determined. At this point in core life Condition A no longer exists. The unit is no longer in the Required Action, so the administrative withdrawal limits are no longer in effect.

B.1

If the required administrative withdrawal limits at BOL are not established within 24 hours, the unit must be brought to MODE 2 with k_{eff} < 1.0 to prevent operation with an MTC that is more positive than that assumed in safety analyses.

The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

C.1

Exceeding the EOL MTC limit means that the safety analysis assumptions for the EOL accidents that use a bounding negative MTC value may be invalid. If the EOL MTC limit is exceeded, the plant must be brought to a MODE or condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 4 within 12 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

This SR requires measurement of the MTC at BOL prior to entering MODE 1 in order to demonstrate compliance with the most positive MTC LCO. Meeting the limit prior to entering MODE 1 ensures that the limit will also be met at higher power levels.

The BOL MTC value for ARO will be inferred from isothermal temperature coefficient measurements obtained during the physics tests after refueling. The ARO value can be directly compared to the BOL MTC limit of the LCO. If required, measurement results and predicted design values can be used to establish administrative withdrawal limits for control banks.

SR 3.1.3.2

In similar fashion, the LCO demands that the MTC be less negative than the specified value for EOL full power conditions. This measurement may be performed at any THERMAL POWER, but its results must be extrapolated to the conditions of RTP and all banks withdrawn in order to make a proper comparison with the LCO value. Because the RTP MTC value will gradually become more negative with further core depletion and boron concentration reduction, a 300 ppm SR value of MTC should necessarily be less negative than the EOL LCO limit. The 300 ppm SR value is sufficiently less negative than the EOL LCO limit value to ensure that the LCO limit will be met when the 300 ppm Surveillance criterion is met.

SR 3.1.3.2 is modified by three Notes that include the following requirements:

1. This SR is not required to be performed until 7 effective full power days (EFPD) after reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm. This note alters the FREQUENCY to once each cycle within 7 effective full power days (EFPD) after reaching the equivalent of an equilibrium RTP ARO boron concentration of 300 ppm.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.3.2 (continued)

2. If the 300 ppm Surveillance limit is exceeded, it is possible that the EOL limit on MTC could be reached before the planned EOL. Because the MTC changes slowly with core depletion, the Frequency of 14 effective full power days is sufficient to avoid exceeding the EOL limit. This note establishes a new required action and completion time. The required action, verify the MTC is within the COLR lower limit (which is a repeat of the surveillance), occurs when the existing surveillance requirement (i.e., to verify the MTC is more positive than the limit specified in the COLR for a 300 ppm boron concentration) fails. The frequency is 14 EFPD after the initial surveillance test fails and every 14 EFPD thereafter.

3. The Surveillance limit for RTP boron concentration of 60 ppm is conservative. If the measured MTC at 60 ppm is more positive than the 60 ppm Surveillance limit, the EOL limit will not be exceeded because of the gradual manner in which MTC changes with core burnup. This note acts to limit the action requirement in Note 2. It allows the action to repeat the surveillance to be terminated if the MTC measured at the equivalent of equilibrium RTP-ARO boron concentration of < 60 ppm is less negative than the 60 ppm surveillance limit specified in the COLR.

REFERENCES

1. 10 CFR 50, Appendix A.

2. FSAR, Chapter 14.

3. WCAP 9273-NP-A, "Westinghouse Reload Safety Evaluation Methodology," July 1985.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

All components of the RCS are designed to withstand effects of cyclic loads due to system pressure and temperature changes. These loads are introduced by startup (heatup) and shutdown (cooldown) operations, power transients, and reactor trips. This LCO limits the pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

LCO 3.4.3, Figure 3.4.3-1, Heatup Limitations for the Reactor Coolant System, Figure, 3.4.3-2, Cooldown Limitations for the Reactor Coolant System, and Figure 3.4.3-3, Hydrostatic and Inservice Leak Testing Limitations for the Reactor Coolant System, contain P/T limit curves for heatup, cooldown, and inservice leak and hydrostatic (ISLH) testing, respectively (Ref. 1).

Each P/T limit curve defines an acceptable region for normal operation. The usual use of the curves is operational guidance during heatup or cooldown maneuvering, when pressure and temperature indications are monitored and compared to the applicable curve to determine that operation is within the allowable region. The happy face icon shown on Figure 3.4.3-1, Figure, 3.4.3-2, and Figure 3.4.3-3, indicates the side of the curve in which operation is permissible. Conversely, the sad face icon indicates the side of the curve in which operation is prohibited.

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the reactor coolant pressure boundary (RCPB). The vessel is the component most subject to brittle failure, and the LCO limits apply mainly to the vessel. The limits do not apply to the pressurizer, which has different design characteristics and operating functions.

(continued)

BASES

BACKGROUND (continued)

10 CFR 50, Appendix G (Ref. 2), requires the establishment of P/T limits for specific material fracture toughness requirements of the RCPB materials. Reference 2 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. It mandates the use of the American Society of Mechanical Engineers (ASME) Code, Section III, Appendix G (Ref. 3).

The neutron embrittlement effect on the material toughness is reflected by increasing the nil ductility reference temperature (RT_{NDT}) as exposure to neutron fluence increases.

The actual shift in the RT_{NDT} of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 4) and Appendix H of 10 CFR 50 (Ref. 5). The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings and the recommendations of Regulatory Guide 1.99 (Ref. 6).

The P/T limit curves are composite curves established by superimposing limits derived from stress analyses of those portions of the reactor vessel and head that are the most restrictive. At any specific pressure, temperature, and temperature rate of change, one location within the reactor vessel will dictate the most restrictive limit. Across the span of the P/T limit curves, different locations are more restrictive, and, thus, the curves are composites of the most restrictive regions.

The heatup curve represents a different set of restrictions than the cooldown curve because the directions of the thermal gradients through the vessel wall are reversed. The thermal gradient reversal alters the location of the tensile stress between the outer and inner walls.

(continued)

BASES

BACKGROUND (continued)

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the RCPB, possibly leading to a nonisolable leak or loss of coolant accident. In the event these limits are exceeded, an evaluation must be performed to determine the effect on the structural integrity of the RCPB components. The ASME Code, Section XI, Appendix E (Ref. 7), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, an unanalyzed condition. Reference 1 establishes the methodology for determining the P/T limits. Although the P/T limits are not derived from any DBA, the P/T limits are acceptance limits since they preclude operation in an unanalyzed condition.

RCS P/T limits satisfy Criterion 2 of 10 CFR 50.36.

LCO

The two elements of this LCO are:

a. The limit curves for heatup, cooldown, and ISLH testing; and

b. Limits on the rate of change of temperature.

Figure 3.4.3-1, Heatup Limitations for the Reactor Coolant System, Figure, 3.4.3-2, Cooldown Limitations for the Reactor Coolant System, and Figure 3.4.3-3, Hydrostatic and Inservice Leak Testing Limitations for the Reactor Coolant System, contain P/T limit curves for heatup, cooldown, and inservice leak and hydrostatic (ISLH) testing, respectively. These figures specify the maximum RCS pressure for various heatup and cooldown rates at

(continued)

BASES

LCO (continued)

any given reactor coolant temperature. The figures provide the limiting RCS pressure and reactor coolant temperature combination for reactor coolant temperature heatup rates up to 60°F/hr and reactor coolant temperature cooldown rates up to 100°F/hr. Therefore, heatup rates that exceed 60°F/hr and cooldown rates that exceed 100°F/hr are considered not within the limits of this LCO.

The LCO limits apply to all components of the RCS pressure boundary, except the pressurizer. These limits define allowable operating regions and permit a large number of operating cycles while providing a wide margin to nonductile failure.

The limits for the rate of change of temperature control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, cooldown, and ISLH testing P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures the validity of the P/T limit curves. Heatup and cooldown limits are specified in hourly increments (i.e., the heatup and cooldown limits are based on the temperature change averaged over a one hour period). Limit lines for cooldown rates between those presented may be obtained by interpolation.

Violating the LCO limits places the reactor vessel outside of the bounds of the stress analyses and can increase stresses in other RCPB components. The consequences depend on several factors, as follows:

a. The severity of the departure from the allowable operating P/T regime or the severity of the rate of change of temperature;

b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and

c. The existence, size, and orientation of flaws in the vessel material.

(continued)

BASES

APPLICABILITY

The RCS P/T limits LCO provides a definition of acceptable operation for prevention of nonductile failure in accordance with 10 CFR 50, Appendix G (Ref. 2). Although the P/T limits were developed to provide guidance for operation during heatup or cooldown (MODES 3, 4, and 5) or ISLH testing, their Applicability is at all times in keeping with the concern for nonductile failure. The limits do not apply to the pressurizer.

During MODES 1 and 2, other Technical Specifications provide limits for operation that can be more restrictive than or can supplement these P/T limits. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits"; LCO 3.4.2, "RCS Minimum Temperature for Criticality"; and Safety Limit 2.1, "Safety Limits," also provide operational restrictions for pressure and temperature and maximum pressure. Furthermore, MODES 1 and 2 are above the temperature range of concern for nonductile failure, and stress analyses have been performed for normal maneuvering profiles, such as power ascension or descent.

ACTIONS

A.1 and A.2

Operation outside the P/T limits during MODE 1, 2, 3, or 4 must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses.

The 30 minute Completion Time reflects the urgency of restoring the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed before continuing operation. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, new analyses, or inspection of the components.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

ASME Code, Section XI, Appendix E (Ref. 7), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

The 72 hour Completion Time is reasonable to accomplish the evaluation. The evaluation for a mild violation is possible within this time, but more severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed before continuing to operate.

Condition A is modified by a Note requiring Required Action A.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action A.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be placed in a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased stress or a sufficiently severe event caused entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced pressure and temperature. In reduced pressure and temperature conditions, the possibility of propagation with undetected flaws is decreased.

If the required restoration activity cannot be accomplished within 30 minutes, Required Action B.1 and Required Action B.2 must be implemented to reduce pressure and temperature.

If the required evaluation for continued operation cannot be accomplished within 72 hours or the results are indeterminate or unfavorable, action must proceed to reduce pressure and temperature as specified in Required Action B.1 and Required

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

Action B.2. A favorable evaluation must be completed and documented before returning to operating pressure and temperature conditions.

Pressure and temperature are reduced by bringing the plant to MODE 3 within 6 hours and to MODE 5 with RCS pressure < 500 psig within 36 hours. Note that LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), will also apply and may require limits for operation that are more restrictive than or supplement this limit.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1 and C.2

Actions must be initiated immediately to correct operation outside of the P/T limits at times other than when in MODE 1, 2, 3, or 4, so that the RCPB is returned to a condition that has been verified by stress analysis.

The immediate Completion Time reflects the urgency of initiating action to restore the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify that the RCPB integrity remains acceptable and must be completed prior to entry into MODE 4. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 7), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Condition C is modified by a Note requiring Required Action C.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action C.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

Verification that operation is within the PTLR limits is required every 30 minutes when RCS pressure and temperature conditions are undergoing planned changes. This Frequency is considered reasonable in view of the control room indication available to monitor RCS status. Heatup and cooldown limits are specified in hourly increments (i.e., the heatup and cooldown limits are based on the temperature change averaged over a one hour period). Also, since temperature rate of change limits are specified in hourly increments, 30 minutes permits assessment and correction for minor deviations within a reasonable time.

Surveillance for heatup, cooldown, or ISLH testing may be discontinued when the definition given in the relevant plant procedure for ending the activity is satisfied.

This SR is modified by a Note that only requires this SR to be performed during system heatup, cooldown, and ISLH testing. No SR is given for criticality operations because LCO 3.4.2 contains a more restrictive requirement.

(continued)

BASES

REFERENCES

1. WCAP-7924-A, July 1972.

2. 10 CFR 50, Appendix G.

3. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.

4. ASTM E 185-70.

5. 10 CFR 50, Appendix H.

6. Regulatory Guide 1.99, Revision 2, May 1988.

7. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

8. WCAP-16037, Revision 1, "Final Report on Pressure-Temperature Limits for Indian Point Unit 3 NPP", Westinghouse Electric Company, May 2003.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Low Temperature Overpressure Protection (LTOP)

BASES

BACKGROUND

LTOP is established to limit RCS pressure at low temperatures so the integrity of the reactor coolant pressure boundary (RCPB) is not compromised by violating the pressure and temperature (P/T) limits of 10 CFR 50, Appendix G (Ref. 1). The reactor vessel is the limiting RCPB component for demonstrating such protection. LCO 3.4.12, Figure 3.4.12-1 provides the maximum allowable nominal actuation logic setpoints for the power operated relief valves (PORVs) and the maximum RCS pressure for the coldest existing RCS cold leg temperature during cooldown, shutdown, and heatup to meet the Reference 1 requirements during the LTOP MODES.

The reactor vessel material is less tough at low temperatures than at normal operating temperature. As the vessel neutron exposure accumulates, the material toughness decreases and becomes less resistant to pressure stress at low temperatures (Ref. 2). RCS pressure, therefore, is maintained low at low temperatures and is increased only as temperature is increased.

The potential for vessel overpressurization is most acute when the RCS is water solid, occurring only while shutdown because a pressure fluctuation can occur more quickly than an operator can react to relieve the condition. Exceeding the RCS P/T limits by a significant amount could cause brittle cracking of the reactor vessel. LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," requires administrative control of RCS pressure and temperature during heatup and cooldown to prevent exceeding the limits in Figure 3.4.12-1.

When the RHR System is isolated from the RCS, the RHR System is protected from overpressure by two spring loaded relief valves (SI-733A and SI-733B). When the RHR System is not isolated from the RCS, the RHR System is protected from overpressure by spring loaded relief valve (i.e., AC-1836) which has sufficient capacity to accommodate all 3 charging pumps. However, this relief

(continued)

BASES

BACKGROUND (continued)

valve does not have sufficient capacity to ensure that the RHR system does not exceed design pressure limits during a mass addition resulting from an inadvertent injection of one or more high head safety injection (HHSI) pumps. Therefore, LTOP requirements are used to protect the RHR System whenever the RHR System is not isolated from the RCS.

This LCO provides RCS overpressure protection by limiting maximum coolant input capability and having adequate pressure relief capacity. Limiting coolant input capability is achieved by not permitting any High Head Safety Injection (HHSI) pumps to be capable of injection into the RCS and isolating the accumulators. The pressure relief capacity requires either two redundant power operated relief valves (PORVs) or a depressurized RCS and an RCS vent of sufficient size. One PORV or the open RCS vent is sufficient to provide overpressure protection to terminate an increasing pressure event. Alternately, if redundant PORVs are not Operable or an RCS vent cannot be established, LTOP protection may be established by limiting the pressurizer level to within limits specified in Figure 3.4.12-2 and Figure 3.4.12-3 consistent with the number of charging pumps and number of high head safety injection (HHSI) pumps capable of injecting into the RCS. This approach is acceptable because pressurizer level can be maintained such that it will either accommodate any anticipated pressure surge or allow operators time to react to any unanticipated pressure surge. When pressurizer level is used to satisfy LTOP requirements, operator action is assumed to terminate the unplanned HHSI pump injection within 10 minutes.

With high pressure coolant input capability limited, the ability to create an overpressure condition by coolant addition is restricted. The LCO does not require the makeup control system deactivated or the safety injection (SI) actuation circuits blocked. Due to the lower pressures in the LTOP MODES and the expected core decay heat levels, the makeup system can provide adequate flow via the makeup control valve. There is no restriction on the status of charging pumps when LTOP is established using either a PORV or an RCS vent. If conditions require the use of more than one HHSI pump for makeup in the event of loss of inventory, then pumps can be made available through

(continued)

BASES

BACKGROUND (continued)

manual actions. Charging pumps and low pressure injection systems are available to provide makeup even when LTOP requirements are applicable.

When configured to provide low temperature overpressure protection, the PORVs are part of the Overpressure Protection System (OPS). LTOP for pressure relief can consist of either the OPS (two PORVs with reduced lift settings), or a depressurized RCS and an RCS vent of sufficient size. Two PORVs are required for redundancy. One PORV has adequate relieving capability to keep from overpressurization for the required coolant input capability.

PORV Requirements

The Overpressure Protection System (OPS) provides the low temperature overpressure protection by controlling the Power Operated Relief Valves (PORVs) and their associated block valves with pressure setpoints that vary with RCS cold leg temperature. Specifically, cold leg temperature signals from three RCS loops are supplied to three associated function generators that calculate the maximum RCS pressures allowed at those temperatures. The maximum RCS pressure limits at any RCS temperature correspond to the 10 CFR 50, Appendix G, limit curve maintained in the Pressure and Temperature Limits Report and are used as the OPS pressure setpoint. Having the setpoints of both valves within the limits in Figure 3.4.12-1 ensures that the Reference 1 limits will not be exceeded in any analyzed event.

In addition to generating the OPS pressure setpoint, the same cold leg temperature signals are used to "arm" the OPS when RCS temperature falls below the temperature at which low temperature overpressure protection is required (319°F). This temperature includes an allowance of 14.4°F for instrument uncertainty and margin. Each PORV opens when a two-out-of-two (temperature and pressure) coincidence logic is satisfied. OPS is "armed" when RCS temperature falls below the temperature that satisfies one half of the two-out-of-two (temperature-pressure) coincidence logic. When OPS is enabled, the PORVs will open if RCS pressure exceeds the calculated pressure setpoint that varies with RCS temperature.

(continued)

BASES

BACKGROUND (continued)

The PORV block valves open when the RCS temperature falls below the OPS arming temperature. Note that the control switches for the PORV and PORV block valves must be in the AUTO position and the OPS states links closed for OPS signals to actuate the PORVs.

Three channels of RCS cold leg temperature are used in the two-out-of-three coincidence logic to satisfy the temperature portion of the two-out-of-two (temperature and pressure) coincidence logic for each PORV. Three channels of RCS pressure are used in a two-out-of-three coincidence logic to satisfy the pressure portion of the two-out-of-two (temperature-pressure) coincidence logic for each PORV. Use of a two-out-of-three coincidence logic for pressure and for temperature ensures that a single failure will not cause or prevent an OPS actuation. Use of two PORVs, each with adequate relieving capability to prevent overpressurization, ensures that a single failure will not prevent an OPS actuation.

When a PORV is opened in an increasing pressure transient, the release of coolant will cause the pressure increase to slow and reverse. As the PORV releases coolant, the RCS pressure decreases until a reset pressure is reached and the valve is signaled to close. The pressure continues to decrease below the reset pressure as the valve closes.

RCS Vent Requirements

Once the RCS is depressurized, a vent exposed to the containment atmosphere will maintain the RCS at containment ambient pressure in an RCS overpressure transient, if the relieving requirements of the transient do not exceed the capabilities of the vent. Thus, the vent path must be capable of relieving the flow resulting from the limiting LTOP mass or heat input transient, and maintaining pressure below the P/T limits. The required vent capacity may be provided by one or more vent paths.

Multiple methods exist for establishing the required RCS vent capacity including removing or blocking open a PORV and disabling its block valve in the open position. An RCS vent of $\geq$ 2.00 square inches when no HHSI pump is capable of injecting into

(continued)

BASES

BACKGROUND (continued)

the RCS; or, an RCS vent with opening greater than or equal to one pressurizer code safety valve flange and up to two HHSI pumps capable of injecting into the RCS will satisfy LTOP requirements because either configuration ensures pressure limits are not exceed during a transient. Alternately, an RCS vent of ≥ 2.00 square inches coupled with a pressurizer level ≤ 0% and up to two HHSI pumps capable of injecting into the RCS will satisfy LTOP requirements because it ensures a minimum of 10 minutes for operator action before pressure limits are exceeded during a transient. The vent path(s) must be above the level of reactor coolant, so as not to drain the RCS when open.

APPLICABLE SAFETY ANALYSES

Safety analyses (Ref. 3) demonstrate that the reactor vessel is adequately protected against exceeding the Reference 1 P/T limits. In MODES 1, 2, and 3, with RCS cold leg temperature exceeding 411°F, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference 1 limits. At 319 °F and below, overpressure prevention falls to two OPERABLE PORVs in conjunction with the Overpressure Protection System (OPS) or to a depressurized RCS and a sufficient sized RCS vent. Each of these means has a limited overpressure relief capability. Alternately, if redundant PORVs are not Operable, Low Temperature Overpressure protection may be maintained by limiting the pressurizer level to within limits specified in Figure 3.4.12-2 and Figure 3.4.12-3 consistent with the number of charging pumps and number of high head safety injection (HHSI) pumps capable of injecting into the RCS. This approach is acceptable because pressurizer level can be established to either accommodate any anticipated pressure surge or allow operators time to react to any unanticipated pressure surge.

When the RCS temperature is greater than the LTOP arming temperature (i.e., ≥ 319°F) but below the minimum temperature at which the pressurizer safety valves lift prior to violation of the 10 CFR 50, Appendix G, limits (i.e., ≤ 380°F), administrative controls in the Technical Requirements Manual (TRM) (Ref. 4) are used to limit the potential for exceeding 10 CFR 50, Appendix G,

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

limits. These administrative controls may include operating with a bubble in the pressurizer and/or otherwise limiting plant time or activities when the RCS temperature is in the specified range. The use of administrative controls to govern operation above the LTOP arming temperature but below the minimum temperature at which the pressurizer safety valves lift prior to violation of the 10 CFR 50, Appendix G, limits is consistent with the guidance provided in Generic Letter 88-011, NRC Position on Radiation Embrittlement of Reactor Vessel Materials and its Impact on Plant Operations (Ref.2). GL 88-011 states that automatic, or passive, protection of the P-T limits will not be required but administratively controlled when in the upper end of the 10 CFR 50, Appendix G, temperature range.

The actual temperature at which the pressure in the P/T limit curve falls below the pressurizer safety valve setpoint increases as the reactor vessel material toughness decreases due to neutron embrittlement. Each time the Figure 3.4.12-1 curves are revised, LTOP must be re-evaluated to ensure its functional requirements can still be met using the OPS (PORVs) method or the depressurized and vented RCS condition.

Figure 3.4.12-1 contains the acceptance limits that define the LTOP requirements. Any change to the RCS must be evaluated against the Ref. 3 analyses to determine the impact of the change on the LTOP acceptance limits.

Transients that are capable of overpressurizing the RCS are categorized as either mass or heat input transients, examples of which follow:

<u>Mass Input Type Transients</u>

a. Inadvertent safety injection; or

b. Charging/letdown flow mismatch.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Heat Input Type Transients

a. Inadvertent actuation of pressurizer heaters;

b. Loss of RHR cooling; or

c. Reactor coolant pump (RCP) startup with temperature asymmetry within the RCS or between the RCS and steam generators.

The following are required during the LTOP MODES to ensure that mass and heat input transients do not occur. This is accomplished by the following:

a. Rendering all HHSI pumps incapable of injection;

b. Deactivating the accumulator discharge isolation valves in their closed positions or maintaining accumulator pressure less than the maximum RCS pressure for the coldest existing RCS cold leg temperature allowed by the P/T limit curves provided in Figure 3.4.12-1; and

c. Disallowing start of an RCP unless conditions are established that ensure a RCP pump start will not cause a pressure excursion that will exceed LTOP limits. Required conditions for starting a RCP when LTOP is required include a combination of primary and secondary water temperature differences and Overpressure Protection System (OPS) status or pressurizer level. Meeting the LTOP RCP starting surveillances ensures that theses conditions are satisfied prior to a RCP pump start.

The Ref. 3 analyses demonstrate that either one PORV or the depressurized RCS and RCS vent can maintain RCS pressure below limits when no HHSI pump is capable of injecting into the RCS. This assumes an RCS vent of ≥ 2.00 square inches. The same protection can be provided when up to two HHSI pumps are capable of injecting into the RCS assuming an RCS vent with opening greater than or equal to one code pressurizer safety valve flange. Alternately, LTOP requirements can be satisfied by various

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

combinations of pressurizer level, RCS pressure, and RCS injection capability (i.e., maximum number of HHSI pumps and/or charging pumps) shown in Figure 3.4.12-2 and 3.4.12-3. These combinations of pressurizer level, RCS pressure, and RCS injection capability satisfy LTOP requirements by ensuring a minimum of 10 minutes for operator action to terminate an unplanned event prior to exceeding maximum allowable RCS pressure. None of the analyses addressed the pressure transient need from accumulator injection, therefore, when RCS temperature is low, the LCO also requires the accumulator isolation when accumulator pressure is greater than or equal to the maximum RCS pressure for the coldest existing RCS cold leg temperature allowed in Figure 3.4.12-1.

If the accumulators are isolated and not depressurized, then the accumulators must have their discharge valves closed and the valve power supply breakers fixed in their open positions.
Fracture mechanics analyses established the temperature of LTOP Applicability at 319 °F.

The consequences of a loss of coolant accident (LOCA) in LTOP MODE 4 conform to 10 CFR 50.46 and 10 CFR 50, Appendix K (Refs. 5 and 6) requirements by having ECCS OPERABLE in accordance with requirements in LCO 3.5.3, ECCS-Shutdown.

PORV Performance

The fracture mechanics analyses show that the vessel is protected when the PORVs are set to open at or below the limit shown in Figure 3.4.12-1. The setpoints are derived by analyses that model the performance of the LTOP System, assuming the limiting LTOP transient with HHSI not injecting into the RCS. These analyses consider pressure overshoot and undershoot beyond the PORV opening and closing, resulting from signal processing and valve stroke times. The PORV setpoints at or below the derived limit ensures the Reference 1 P/T limits will be met. The OPS setpoint is based

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BASES

APPLICABLE SAFETY ANALYSES (continued)

on a comparative analysis of Reference 3, with allowances for metal/fluid temperature differences, static head due to elevation differences, and dynamic head from the operation of the reactor coolant pumps and RHR pumps.

The PORV setpoints in Figure 3.4.12-1 will be updated when the revised P/T limits conflict with the LTOP analysis limits. The P/T limits are periodically modified as the reactor vessel material toughness decreases due to neutron embrittlement caused by neutron irradiation. Revised limits are determined using neutron fluence projections and the results of examinations of the reactor vessel material irradiation surveillance specimens. The Bases for LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," discuss these examinations.

The PORVs are considered active components. Thus, the failure of one PORV is assumed to represent the worst case, single active failure.

RCS Vent Performance

With the RCS depressurized, analyses show a vent size of 1.4 square inches is capable of mitigating the allowed LTOP overpressure transient assuming no HHSI pump and no accumulator injects into the RCS. The LCO limit for an RCS vent is conservatively established at 2.00 square inches. The capacity of a vent this size is greater than the flow of the limiting transient for the LTOP configuration, maintaining RCS pressure less than the maximum pressure on the P/T limit curve. An RCS vent with opening greater than or equal to one pressurizer code safety valve flange and up to two HHSI pumps capable of injecting into the RCS will satisfy LTOP requirements because it ensures pressure limits are not exceed during a transient. An RCS vent of ≥ 2.00 square inches coupled with a pressurizer level ≤ 0% and up to two HHSI pumps capable of injecting into the RCS will satisfy

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

LTOP requirements because it ensures a minimum of 10 minutes for operator action before pressure limits are exceeded during a transient.

The RCS vent size will be re-evaluated for compliance each time the P/T limit curves are revised based on the results of the vessel material surveillance.

The RCS vent is passive and is not subject to active failure.

LTOP satisfies Criterion 2 of 10 CFR 50.36.

LCO

This LCO requires that LTOP is OPERABLE. LTOP is OPERABLE when the minimum coolant input and pressure relief capabilities are OPERABLE. Violation of this LCO could lead to the loss of low temperature overpressure mitigation and violation of the Reference 1 limits as a result of an operational transient.

To limit the coolant input capability, the LCO requires that no HHSI pumps be capable of injecting into the RCS and all accumulator discharge isolation valves closed and de-energized if accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in Figure 3.4.12-1, Maximum Allowable Nominal PORV Setpoint for LTOP (OPS).

The elements of the LCO that provide low temperature overpressure mitigation through pressure relief are:

a. Two OPERABLE PORVs configured as part of an OPERABLE Overpressure Protection System (OPS); or

b. A depressurized RCS and an RCS vent.

A PORV is OPERABLE for LTOP when its block valve is open, its lift setpoint is set to the limit required by Figure 3.4.12-1 and testing proves its ability to open at this setpoint, and motive power is available to the two valves and their control circuits.

(continued)

BASES

LCO (continued)

The OPS is OPERABLE for LTOP when there are three OPERABLE RCS pressure channels and three OPERABLE RCS temperature channels. The OPS is still OPERABLE when an inoperable RCS pressure or temperature channel is in the tripped condition. OPS is considered OPERABLE for meeting LCO 3.4.12 requirements even if one or two RCS cold leg temperatures is above the LTOP Applicability limit.

An RCS vent is OPERABLE when open with an area of ≥ 2.00 square inches.

Each of these methods of overpressure prevention is capable of mitigating the limiting LTOP transient.

APPLICABILITY

This LCO is applicable whenever the RHR System is not isolated from the RCS to protect the RHR system piping. When all RCS cold leg temperatures are ≥ 319 °F, RHR system piping is adequately protected by making the accumulators and all HHSI pumps incapable of injecting into the RCS. Therefore, a Note in the LCO specifies that requirements for the OPS System and/or an RCS vent are not Applicable when all RCS cold leg temperatures are ≥ 319 °F.

This LCO is applicable to provide protection for the RCS pressure boundary in MODE 4 when any RCS cold leg temperature is < 319 °F, in MODE 5, and in MODE 6 when the reactor vessel head is on. The pressurizer safety valves provide overpressure protection that meets the Reference 1 P/T limits above 319 °F. When the reactor vessel head is off, overpressurization cannot occur. Although LTOP is not Applicable when the RCS temperature is greater than the LTOP arming temperature (i.e., ≥ 319 °F) but below the minimum temperature at which the pressurizer safety valves lift prior to violation of the 10 CFR 50, Appendix G, limits (i.e., ≤ 380 °F), administrative controls in the Technical Requirements Manual (TRM) (Ref. 4) are used to limit the potential for exceeding 10 CFR 50, Appendix G, limits. LCO 3.4.3 provides the operational P/T limits

(continued)

BASES

APPLICABILITY (continued)

for all MODES. LCO 3.4.10, "Pressurizer Safety Valves," requires the OPERABILITY of the pressurizer safety valves that provide overpressure protection during MODES 1, 2, and 3, and MODE 4 above 319 °F when the RHR system is isolated from the RCS.

Low temperature overpressure prevention is most critical during shutdown when the RCS is water solid, and a mass or heat input transient can cause a very rapid increase in RCS pressure when little or no time allows operator action to mitigate the event.

The Applicability is modified by three Notes, Note 1 states that accumulator isolation is only required when the accumulator pressure is more than the maximum RCS pressure for the existing temperature, as allowed by the P/T limit curves. This Note permits the accumulator discharge isolation valve Surveillance to be performed only under these pressure and temperature conditions.

Note 2 ensures that LCO 3.4.12 will not prohibit a HHSI pump being energized and aligned to the RCS as needed to support emergency boration or to respond to a loss of RHR cooling.

Note 3 specifies that one HHSI pump may be made capable of injecting into the RCS for a period not to exceed 8 hours to perform pump testing. During testing, administrative controls are used to ensure that HHSI testing will not result in exceeding RCS or RHR system pressure limits.

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.3.1 and A.3.2

When one or more HHSI pumps are capable of injecting into the RCS, LTOP assumptions regarding limits on mass input capability may not be met. Therefore, immediate action is required to limit injection capability consistent with the LTOP analysis assumptions and the existing combination of pressurizer level and RCS venting capacity. Required Action A.1 requires restoration with LCO

(continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.3.1 and A.3.2 (continued)

requirements. Required Actions A.2 and A.3 require verification and periodic re-verification that alternate LTOP configurations are met. The Completion Times of immediately reflects the urgency that one of the acceptable LTOP configurations is established as soon as possible.

B.1, C.1 and C.2

To be considered isolated, an accumulator must have its discharge valves closed and the valve power supply breakers fixed in the open position.

An unisolated accumulator requires isolation within 1 hour. This is only required when the accumulator pressure is at or more than the maximum RCS pressure for the existing temperature allowed by the P/T limit curves.

If isolation is needed and cannot be accomplished in 1 hour, Required Action C.1 and Required Action C.2 provide two options, either of which must be performed in the next 12 hours. By increasing the RCS temperature to ≥ 319 °F, an accumulator pressure of 700 psig cannot exceed the LTOP limits if the accumulators are injected. Isolating the RHR system from the RCS ensures that the RHR system is not subjected to accumulator pressure. Depressurizing the accumulators below the LTOP limit from Figure 3.4.12-1 also gives this protection. Additionally, the RHR System must be isolated from the RCS to protect RHR piping from a potential mass addition event.

The Completion Times are based on operating experience that these activities can be accomplished in these time periods and on engineering evaluations indicating that an event requiring LTOP is not likely in the allowed times.

(continued)

BASES

ACTIONS (continued)

D.1

When any RCS cold leg temperature is < 319 °F, with one required PORV inoperable, the PORV must be restored to OPERABLE status within a Completion Time of 7 days. Two PORVs are required to provide low temperature overpressure mitigation while withstanding a single failure of an active component.

The Completion Time considers the facts that only one of the PORVs is required to mitigate an overpressure transient and that the likelihood of an active failure of the remaining valve path during this time period is very low.

E.1

When both required PORVs are inoperable or the Required Action and associated Completion Time of Condition C or D is not met, an alternate method of low temperature overpressure protection must be established within 8 hours. The acceptable alternate methods of LTOP include the following:

a. Depressurize the RCS and establish an RCS vent path; or

b. Increase all RCS cold leg temperatures to ≥ 319°F and isolate the RHR system from the RCS; or

If the option selected is to depressurize the RCS and establish an RCS vent path, the vent must be sized ≥ 2.00 square inches to ensure that the flow capacity is greater than that required for the worst case mass input transient reasonable during the applicable MODES. This action is needed to protect the RCPB from a low temperature overpressure event and a possible brittle failure of the reactor vessel.

The Completion Time considers the time required to place the plant in this Condition and the relatively low probability of an overpressure event during this time period due to increased operator awareness of administrative control requirements.

(continued)

BASES

ACTIONS (continued)

F.1

If LTOP requirements are not met for reasons other than Conditions A, B, C, D or E, LTOP requirements must be re-established by depressurizing the RCS and establishing an RCS vent of ≥ 2.00 square inches within 8 hours.

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1 and SR 3.4.12.2

To minimize the potential for a low temperature overpressure event by limiting the mass input capability, all HHSI pumps are verified incapable of injecting into the RCS. Additionally, the accumulator discharge isolation valves are verified closed and locked out or the accumulator pressure less than the maximum RCS pressure for the existing RCS cold leg temperature allowed by the P/T limit curves provided in Figure 3.4.12-1.

The HHSI pumps are rendered incapable of injecting into the RCS through removing the power from the pumps by racking the breakers out under administrative control. Other methods may be employed using at least two independent means to prevent a pump start such that a single failure or single action will not result in an injection into the RCS. This may be accomplished through the pump control switch being placed in Trip Pullout and at least one valve in the discharge flow path being closed.

The Frequency of 12 hours is sufficient, considering other indications and alarms available to the operator in the control room, to verify the required status of the equipment.

SR 3.4.12.3

The RCS vent of ≥ 2.00 square inches is proven OPERABLE by verifying its open condition either:

a. Once every 12 hours for a valve that is not locked.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.12.3 (continued)

b. Once every 31 days for a valve that is locked, sealed, or secured in position. A removed pressurizer safety valve, PORV, or Manway Cover fits this category.

The passive vent arrangement must only be open to be OPERABLE. This Surveillance is required to be performed if the vent is being used to satisfy the pressure relief requirements of the LCO 3.4.12.b.

SR 3.4.12.4

Performance of the CHANNEL CHECK of the Overpressure Protection System (OPS) RCS pressure and temperature channels every 24 hours ensures that gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.12.4 (continued)

operational use of the displays associated with the LCO required channels. This SR is required only when LCO 3.4.12.a is used to establish LTOP protection.

SR 3.4.12.5

The PORV block valve opens automatically when RCS cold leg temperature is below the OPS arming temperature; however, the valves must be verified open every 72 hours to provide the flow path for each required PORV to perform its function when actuated. The valve may be remotely verified open in the control room. This Surveillance is performed only if the PORV is being used to satisfy LCO 3.4.12.a.

The block valve is a remotely controlled, motor operated valve. The power to the valve operator is not required removed, and the manual operator is not required locked in the inactive position. Thus, the block valve can be closed in the event the PORV develops excessive leakage or does not close (sticks open) after relieving an overpressure situation. If closed, the block valve must be de-energized to prevent the valve from re-opening automatically.

The 72 hour Frequency is considered adequate because the PORV block valves are opened automatically by the OPS when below the OPS arming temperature if the valve control is positioned to auto and other administrative controls available to the operator in the control room, such as valve position indication, that verify that the PORV block valve remains open.

SR 3.4.12.6

Performance of a COT is required within 12 hours after decreasing all RCS temperatures to < 319 °F and every 31 days on each required PORV to verify and, as necessary, adjust its lift setpoint.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.12.6 (continued)

The COT will verify the setpoint is within the allowed maximum limits in Figure 3.4.12-1. PORV actuation could depressurize the RCS and is not required.

The 24 month Frequency considers the demonstrated reliability of the Overpressure Protection System and the PORVs.

A Note has been added indicating that this SR is required to be met 12 hours after decreasing RCS cold leg temperature to < 319 °F. The COT cannot be performed until in the LTOP MODES when the PORV lift setpoint can be reduced to the LTOP setting. The test must be performed within 12 hours after entering the LTOP MODES.

SR 3.4.12.7

Performance of a CHANNEL CALIBRATION on each required PORV actuation channel is required every 18 months. Performance of a CHANNEL CALIBRATION of RCS pressure and temperature instruments that support the Overpressure Protection System is required every 24 months. These calibrations verify both the OPS and PORV function and ensure the OPERABILITY of the whole channel so that it responds and the valve opens within the required range and accuracy to known input.

SR 3.4.12.8 and SR 3.4.12.9

The RCP starting prerequisites must be satisfied prior to starting or jogging any reactor coolant pump (RCP) when low temperature overpressure protection is required. The RCP starting prerequisites prevent an overpressure event due to thermal transients when an RCP is started. Plant conditions prior to the RCP start determines whether SR 3.4.12.8 or SR 3.4.12.9 must be satisfied prior to starting any RCP.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.12.8 and SR 3.4.12.9 (continued)

The principal contributor to an RCP start induced thermal and pressure transient is the difference between RCS cold leg temperatures and secondary side water temperature of any SG prior to the start of an RCP. The RCP starting prerequisites vary depending on plant conditions but include the following: reactor coolant temperature relative to the LTOP enable temperature; secondary side water temperature of the hottest SG relative to the temperature of the coldest RCS cold leg temperature; and, status of the Overpressure Protection System (OPS). When the OPS is inoperable, additional compensatory requirements are required including limits for the pressurizer level and RCS pressure and temperature. When a pressurizer level is specified as a requirement, the level specified is sufficient to prevent the RCS from going water solid for 10 minutes which is sufficient time for operator action to terminate the pressure transient.

SR 3.4.12.8 is used if secondary side water temperature of the hottest steam generator (SG) is less than or equal to the coldest RCS cold leg temperature. SR 3.4.12.9 is more restrictive and is used if the secondary side water temperature of the hottest steam generator is $\leq$ 64 °F above the coldest RCS cold leg temperature.

RCP starting is prohibited if the hottest steam generator is > 64 °F above RCS cold leg temperature or if neither of the RCP starting prerequisites SRs can be satisfied. The steam generator temperature may be measured using the Control Room instrumentation or, as a backup, from a contact reading off the steam generator's shells. Pressurizer level may be determined using control room instrumentation or alternate methods.

The FREQUENCY of the RCP starting prerequisites SRs is within 15 minutes prior to starting any RCP. This means that each of the required verifications must be performed within 15 minutes prior to the pump start and must be met at the time of the pump start.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.12.8 and SR 3.4.12.9 (continued)

SR 3.4.12.8 and SR 3.4.12.9 are each modified by two Notes. Note 1 specifies that these SRs are required as a condition for pump starting only when the RCS is below the LTOP arming temperature. Note 2 specifies that meeting either SR 3.4.12.8 or SR 3.4.12.9 ensures that pump starting prerequisites are met.

REFERENCES

1. 10 CFR 50, Appendix G.
2. Generic Letter 88-011, NRC Position on Radiation Embrittlement of Reactor Vessel Materials and its Impact on Plant Operations.
3. IP3 Low Temperature Overpressurization System Analysis Final Report, August 24, 1984, in conjunction with ASME Code Case N-514, Low Temperature Overpressure Protection, February 12, 1992.
4. IP3 Technical Requirements Manual.
5. 10 CFR 50, Section 50.46.
6. 10 CFR 50, Appendix K.
7. WCAP-16037, Revision 1, "Final Report on Pressure-Temperature Limits for Indian Point Unit 3 NPP", Westinghouse Electric Company, May 2003.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.1 Accumulators

BASES

BACKGROUND

The functions of the ECCS accumulators are to supply water to the reactor vessel during the blowdown phase of a loss of coolant accident (LOCA), to provide inventory to help accomplish the refill phase that follows thereafter, and to provide Reactor Coolant System (RCS) makeup for any LOCA that reduces RCS pressure to below the accumulator pressure.

The blowdown phase of a large break LOCA is the initial period of the transient during which the RCS departs from equilibrium conditions, and heat from fission product decay, hot internals, and the vessel continues to be transferred to the reactor coolant. The blowdown phase of the transient ends when the RCS pressure falls to a value approaching that of the containment atmosphere.

In the refill phase of a LOCA, which immediately follows the blowdown phase, reactor coolant inventory has vacated the core through steam flashing and ejection out through the break. The core is essentially in adiabatic heatup. The balance of accumulator inventory is then available to help fill voids in the lower plenum and reactor vessel downcomer so as to establish a recovery level at the bottom of the core and ongoing reflood of the core with the addition of safety injection (SI) water.

The accumulators are pressure vessels partially filled with borated water and pressurized with nitrogen gas. The accumulators are passive components, since no operator or control actions are required in order for them to perform their function. Internal accumulator tank pressure is sufficient to discharge the accumulator contents to the RCS, if RCS pressure decreases below the accumulator pressure.

Each accumulator is piped into an RCS cold leg via an accumulator line and is isolated from the RCS by a motor operated isolation valve and two check valves in series.

(continued)

BASES

BACKGROUND (continued)

The accumulator size, water volume, and nitrogen cover pressure are selected so that three of the four accumulators are sufficient to partially cover the core before significant clad melting or zirconium water reaction can occur following a LOCA. The need to ensure that three accumulators are adequate for this function is consistent with the LOCA assumption that the entire contents of one accumulator will be lost via the RCS pipe break during the blowdown phase of the LOCA.

APPLICABLE SAFETY ANALYSES

The accumulators are assumed OPERABLE in both the large and small break LOCA analyses at full power (Ref. 1). These are the Design Basis Accidents (DBAs) that establish the acceptance limits for the accumulators. Reference to the analyses for these DBAs is used to assess changes in the accumulators as they relate to the acceptance limits.

In performing the LOCA calculations, conservative assumptions are made concerning the availability of ECCS flow. In the early stages of a LOCA, with or without a loss of offsite power, the accumulators provide the sole source of makeup water to the RCS. The assumption of loss of offsite power is required by regulations and conservatively imposes a delay wherein the ECCS pumps cannot deliver flow until the emergency diesel generators start, come to rated speed, and go through their timed loading sequence. In cold leg break scenarios, the entire contents of one accumulator are assumed to be lost through the break.

The limiting large break LOCA is a double ended guillotine break at the discharge of the reactor coolant pump. During this event, the accumulators discharge to the RCS as soon as RCS pressure decreases to below accumulator pressure.

As a conservative estimate, no credit is taken for ECCS pump flow until an effective delay has elapsed. This delay accounts for the diesels starting and the pumps being loaded and delivering full flow. The delay time is conservatively set with an additional 2 seconds to account for SI signal generation. During this time,

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

the accumulators are analyzed as providing the sole source of emergency core cooling. No operator action is assumed during the blowdown stage of a large break LOCA.

The worst case small break LOCA analyses also assume a time delay before pumped flow reaches the core. For the larger range of small breaks, the rate of blowdown is such that the increase in fuel clad temperature is terminated solely by the accumulators, with pumped flow then providing continued cooling. As break size decreases, the accumulators and high head safety injection (HHSI) pumps both play a part in terminating the rise in clad temperature. As break size continues to decrease, the role of the accumulators continues to decrease until they are not required and the HHSI pumps become solely responsible for terminating the temperature increase.

This LCO helps to ensure that the following acceptance criteria established for the ECCS by 10 CFR 50.46 (Ref. 2) will be met following a LOCA:

a. Maximum fuel element cladding temperature is $\leq 2200^{o}F$;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react; and

d. Core is maintained in a coolable geometry.

Since the accumulators discharge during the blowdown phase of a LOCA, they do not contribute to the long term cooling requirements of 10 CFR 50.46.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

For both the large and small break LOCA analyses, a nominal contained accumulator water volume is used. The contained water volume is the same as the deliverable volume for the accumulators, since the accumulators are emptied, once discharged.

Accumulator tank size and accumulator water volume directly affect the volume of nitrogen cover gas whose expansion produces the passive injection and thus affects injection rate. The amount of water is also important since the accumulator water which has not been injected and bypassed during blowdown is primarily responsible for filling the lower plenum (refill) and downcomer. The elevation head of the downcomer water provides the driving force for core reflooding (Ref. 3).

For large break LOCAs, changes in accumulator water volume can result in either improved or worsened analysis results; therefore, a nominal accumulator water volume of 795 cubic feet is modeled in the analysis (Ref. 3).

For small break LOCAs, changes in accumulator water volume are not significant because the clad temperature transient is terminated before the accumulators empty; therefore, a nominal accumulator water volume of 795 cubic feet is modeled in the analysis (Ref. 3).

The minimum boron concentration setpoint is used in the post LOCA boron concentration calculation. The calculation is performed to assure reactor subcriticality in a post LOCA environment. Of particular interest is the large break LOCA, since no credit is taken for control rod assembly insertion. A reduction in the accumulator minimum boron concentration would produce a subsequent reduction in the available containment sump concentration for post LOCA shutdown and an increase in the maximum sump pH. The maximum boron concentration is used in determining the cold leg to hot leg recirculation injection switchover time and minimum sump pH.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The large and small break LOCA analyses are performed at the minimum nitrogen cover pressure, since sensitivity analyses have demonstrated that higher nitrogen cover pressure results in a computed peak clad temperature benefit. The maximum nitrogen cover pressure limit prevents injection of nitrogen into the RCS, accumulator relief valve actuation, and ultimately preserves accumulator integrity.

The effects on containment mass and energy releases from the accumulators are accounted for in the appropriate analyses (Refs. 3 and 4).

The accumulators satisfy Criterion 3 of 10 CFR 50.36.

LCO

The LCO establishes the minimum conditions required to ensure that the accumulators are available to accomplish their core cooling safety function following a LOCA. Four accumulators are required to ensure that 100% of the contents of three of the accumulators will reach the core during a LOCA. This is consistent with the assumption that the contents of one accumulator spill through the break. If less than three accumulators are injected during the blowdown phase of a LOCA, the ECCS acceptance criteria of 10 CFR 50.46 (Ref. 2) could be violated.

For an accumulator to be considered OPERABLE, the isolation valve must be fully open, power removed above 2000 psig, and the limits established in the SRs for contained volume, boron concentration, and nitrogen cover pressure must be met.

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS pressure > 1000 psig, the accumulator OPERABILITY requirements are based on full power operation. Although cooling requirements decrease as power decreases, the accumulators are still required to provide core cooling as long as elevated RCS pressures and temperatures exist.

This LCO is only applicable at pressures > 1000 psig. At pressures ≤ 1000 psig, the rate of RCS blowdown is such that the

(continued)

BASES

APPLICABILITY (continued)

ECCS pumps can provide adequate injection to ensure that peak clad temperature remains below the 10 CFR 50.46 (Ref. 2) limit of 2200°F.

In MODE 3, with RCS pressure ≤ 1000 psig, and in MODES 4, 5, and 6, the accumulator motor operated discharge isolation valves are closed to isolate the accumulators from the RCS. This allows RCS cooldown and depressurization without discharging the accumulators into the RCS or requiring depressurization of the accumulators.

Note 1 provides an exception to SR 3.5.1.1 and SR 3.5.1.5 and specifies that all accumulator discharge isolation valves may be closed and energized for up to 8 hours during the performance of reactor coolant system hydrostatic testing. This allowance is necessary because limits imposed by the Pressure/Temperature Limits for a hydrostatic leak test, could, in some instances, require reactor coolant system hydrostatic testing above 350°F (Mode 3). This allowance is acceptable because hydrostatic testing is performed in MODE 3 when the need for the accumulators is reduced and Note 1 limits the duration to the time needed to perform required testing.

Note 2 also provides an exception to SR 3.5.1.1 and SR 3.5.1.5 and specifies that one accumulator discharge isolation valve may be closed and energized in MODE 3 for up to 8 hours for accumulator check valve leakage testing. This allowance is acceptable because testing is limited to MODE 3 when the need for the accumulators is reduced and Note 2 limits the duration to the time needed to perform required testing.

ACTIONS

A.1

If the boron concentration of one accumulator is not within limits, it must be returned to within the limits within 72 hours. In this Condition, ability to maintain subcriticality or minimum boron precipitation time may be reduced. The boron in the accumulators contributes to the assumption that the combined ECCS water in the partially recovered core during the early reflooding phase of a large break LOCA is sufficient to keep that portion of

(continued)

BASES

ACTIONS

A.1 (continued)

the core subcritical. One accumulator below the minimum boron concentration limit, however, will have no effect on available ECCS water and an insignificant effect on core subcriticality during reflood. Boiling of ECCS water in the core during reflood concentrates boron in the saturated liquid that remains in the core. In addition, current analysis techniques demonstrate that the accumulators do not discharge following a large main steam line break. Even if they do discharge, their impact is minor and not a design limiting event. Thus, 72 hours is allowed to return the boron concentration to within limits.

B.1

If one accumulator is inoperable for a reason other than boron concentration, the accumulator must be returned to OPERABLE status within 24 hours. In this Condition, the required contents of three accumulators cannot be assumed to reach the core during a LOCA. Due to the severity of the consequences should a LOCA occur in these conditions, the 24 hour Completion Time to open the valve, remove power to the valve, or restore the proper water volume or nitrogen cover pressure ensures that prompt action will be taken to return the inoperable accumulator to OPERABLE status. The Completion Time minimizes the potential for exposure of the plant to a LOCA under these conditions. The 24 hours allowed to restore an inoperable accumulator to OPERABLE status is justified in WCAP-15049-A, Rev. 1 (Ref. 4).

C.1 and C.2

If the accumulator cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and reactor coolant pressure reduced to $\leq$ 1000 psig within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

D.1

If more than one accumulator is inoperable, the plant is in a condition outside the accident analyses; therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

Each accumulator valve should be verified to be fully open every 12 hours. This verification ensures that the accumulators are available for injection and ensures timely discovery if a valve should be less than fully open. If a discharge isolation valve is not fully open, the rate of injection to the RCS would be reduced. Although a motor operated valve position should not change with power removed, a closed valve could result in not meeting accident analyses assumptions. This Frequency is considered reasonable in view of other administrative controls that ensure a mispositioned isolation valve is unlikely.

SR 3.5.1.2 and SR 3.5.1.3

Every 12 hours, borated water volume and nitrogen cover pressure are verified for each accumulator. This Frequency is sufficient to ensure adequate injection during a LOCA. Because of the static design of the accumulator, a 12 hour Frequency usually allows the operator to identify changes before limits are reached. Operating experience has shown this Frequency to be appropriate for early detection and correction of off normal trends.

SR 3.5.1.4

The boron concentration should be verified to be within required limits for each accumulator every 31 days since the static design of the accumulators limits the ways in which the concentration can be changed. The 31 day Frequency is adequate to identify changes that could occur from mechanisms such as stratification or

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.4 (continued)

inleakage. Sampling the affected accumulator within 6 hours after an increase of 8.4 cubic feet will identify whether inleakage has caused a reduction in boron concentration to below the required limit. Considering the nominal accumulator volume of 795 cubic feet of water, inleakage of 8.4 cubic feet of pure water would result in a boron concentration reduction of approximately 1%. An increase in the accumulator volume of 8.4 cubic feet causes a change of approximately 10% in the indicated accumulator level. It is not necessary to verify boron concentration if the added water inventory is from the refueling water storage tank (RWST), because the water contained in the RWST is within the accumulator boron concentration requirements. This is consistent with the recommendation of NUREG-1366 (Ref. 5).

SR 3.5.1.5

Verification every 31 days that power is removed from each accumulator discharge isolation valve operator when the reactor coolant system pressure is $\geq$ 2000 psig ensures that an active failure could not result in the undetected closure of an accumulator motor operated isolation valve. If this were to occur, only two accumulators would be available for injection given a single failure coincident with a LOCA. Since power is removed under administrative control, the 31 day Frequency will provide adequate assurance that power is removed.

This SR allows power to be supplied to the motor operated discharge isolation valves when reactor coolant system pressure is < 2000 psig, thus allowing operational flexibility by avoiding unnecessary delays to manipulate the breakers during plant startups or shutdowns. Should closure of a valve occur, the SI signal provided to the valves would open a closed valve in the event of a LOCA.

(continued)

BASES

REFERENCES

1. FSAR, Chapter 6.
2. 10 CFR 50.46.
3. FSAR, Chapter 14.
4. WCAP-15049-A, Rev. 1, April 1999.
5. NUREG-1366, February 1990.

B 3.3 INSTRUMENTATION

B 3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

BASES

BACKGROUND

The DGs provide a source of emergency power when offsite power is either unavailable or is insufficiently stable to allow safe unit operation. Undervoltage protection will generate a DG start if a loss of voltage or degraded voltage condition occurs on a 480 V bus.

Two undervoltage relays are provided on each 480 V bus for detecting a bus undervoltage. Either of the two relays is sufficient to satisfy requirements for the 480 V bus undervoltage Function even though the failure of the one remaining undervoltage relay could result in the failure of one DG to start because there is redundancy in the number of EDGs available. The two undervoltage relays are combined in a one-out-of-two logic per bus to generate an undervoltage signal. The allowable value and trip setpoint for this function is established in accordance with Reference 3. Actuation of these relays will trip the bus supply breaker, initiate load shedding, start the DG, and initiate load sequencing. There is no explicit time delay for this function because the undervoltage protection devices are induction type disc relays. Therefore, the time to actual trip will decrease as a function of voltage decrease below the setpoint.

Two degraded voltage relays are provided on each 480 V bus for detecting degraded bus voltage. The relays are combined in a two-out-of-two logic per bus (to prevent spurious actuation). The allowable value and trip setpoint for this function is established in accordance with Reference 3. Function actuation includes a time delay of 10 seconds if a coincident SI signal indicates accident conditions exist and a time delay of 45 seconds if no SI signal is generated (i.e., non-accident condition). These time delays ensure proper coordination with plant electrical transients (e.g. large motor starts, fast transfers, etc.). Actuation of these relays will trip the bus supply breaker, which will in turn actuate the undervoltage relays.

(continued)

BASES

BACKGROUND (continued)

The LOP start actuation is described in FSAR, Section 8.2 (Ref. 1).

Trip Setpoints and Allowable Values

Technical Specification Allowable Values are determined based on the relationship between an analytical limit and a calculated trip setpoint. A detailed discussion of the relative position of the safety limit, analytical limit, allowable value and the trip setpoint with respect to the normal plant operation point is presented in the Bases of LCO 3.3.1, Reactor Protection System (RPS) Instrumentation.

A detailed description of the methodology used to calculate the channel Allowable and bistable device, including their explicit uncertainties, is provided in Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3) (Ref. 3).

APPLICABLE SAFETY ANALYSES

The LOP DG start instrumentation is required for the Engineered Safety Features (ESF) Systems to function in any accident with a loss of offsite power. Its design basis is that of the ESF Actuation System (ESFAS).

Accident analyses credit the loading of the DG based on the loss of offsite power during a loss of coolant accident (LOCA). The actual DG start has historically been associated with the ESFAS actuation. The DG loading has been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power.

The required channels of LOP DG start instrumentation, in conjunction with the ESF systems powered from the DGs, provide unit protection in the event of any of the analyzed accidents discussed in Reference 2, in which a loss of offsite power is assumed.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The delay times assumed in the safety analysis for the ESF equipment include the 10 second DG start delay, and the appropriate sequencing delay. The response times for ESFAS actuated equipment in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," include the appropriate DG loading and sequencing delay.

The LOP DG start instrumentation channels satisfy Criterion 3 of 10 CFR 50.36.

LCO

The LCO for LOP DG start instrumentation requires that 1 channel per bus of the undervoltage (480 V bus) Function and two channels per bus of the Degraded Voltage (480 V bus) Function must be OPERABLE in MODES 1, 2, 3 and 4 when the LOP DG start instrumentation supports safety systems associated with the ESFAS. In MODES 5 and 6, 1 channel per bus of the undervoltage (480 V bus) Function and two channels per bus of the Degraded Voltage (480 V bus) Function must be OPERABLE whenever the associated DG is required to be OPERABLE to ensure that the automatic start of the DG is available when needed.

APPLICABILITY

The LOP DG Start Instrumentation Functions are required in MODES 1, 2, 3, and 4 because ESF Functions are designed to provide protection in these MODES. Actuation in MODE 5 or 6 is required whenever the required DG must be OPERABLE so that it can perform its function on an LOP or degraded power to the vital bus.

ACTIONS

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the channel is found inoperable, then the function that channel provides must be declared inoperable and the LCO Condition entered for the particular protection function affected.

(continued)

BASES

ACTIONS (continued)

Because the required channels are specified on a per bus basis, the Condition may be entered separately for each bus as appropriate. A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in the LCO. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to the LOP DG start Function with one required channel of the undervoltage function inoperable. Note that LCO 3.3.5 requires that only one of the two undervoltage (480 V bus) channels must be OPERABLE. Therefore, Condition A applies when there is no OPERABLE undervoltage (480 V bus) channel on one or more 480 volt vital bus(es).

If one required channel is inoperable or one or more 480 V buses, Required Action A.1 requires that channel to be restored to OPERABLE status within 1 hour.

The specified Completion Time of 1 hour to restore an undervoltage (480 V bus) channels to OPERABLE status is needed because this Condition represents a loss of the undervoltage DG starting Function for the associated DG. The 1 hour delay in declaring the DG inoperable is acceptable because of the low probability of an event occurring during this interval.

B.1

Condition B applies when one of the two required degraded voltage channels is inoperable on one or more 480 V bus. Required Action B.1 requires placing the inoperable channel in trip so that trip capability is restored to the 2 out of 2 logic used to initiate this Function. The 1 hour Completion Time takes into account the low probability of an event requiring an LOP start occurring during this interval.

(continued)

BASES

ACTIONS (continued)

C.1

Condition C applies to each of the LOP DG start Functions when the Required Action and associated Completion Time for Condition A or B are not met. Condition C also applies when two channels of Degraded Voltage Function inoperable in one or more buses. In this Condition, Function trip capability is lost even if one of the channels is placed in trip as specified in Required Action B.1.

In these circumstances the Conditions specified in LCO 3.8.1, "AC Sources—Operating," or LCO 3.8.2, "AC Sources—Shutdown," for the DG made inoperable by failure of the LOP DG start instrumentation are required to be entered immediately. The actions of those LCOs provide for adequate compensatory actions to assure unit safety.

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

SR 3.3.5.1 is the performance of a TADOT. This test is performed every 31 days. The test checks trip devices that provide actuation signals directly, bypassing the analog process control equipment. The Frequency is based on the known reliability of the relays and controls and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

This SR excludes verification of setpoints from the TADOT. Since this TADOT applies to 480 V degraded voltage and undervoltage, setpoint verification requires bench calibration and is accomplished during CHANNEL CALIBRATION. Although the SR is not modified by a note, this is a non-conservative SR whose intent was never to require pulling relays for bench testing. The 480 Volt Bus degraded voltage is sensed by two (2) undervoltage relays per bus. A trip signal requires both relays to sense the degraded voltage condition so pulling a relay makes EDGs inoperable. NRC Administrative Letter 98-10 requires non-conservative Technical Specification requirements to be treated as a nonconforming

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

condition under Generic Letter 91-18 with administrative controls (i.e., the clarification in this Basis) in place until a change to the Technical Specification is processed.

SR 3.3.5.2

SR 3.3.5.2 is the performance of a CHANNEL CALIBRATION.

The setpoints, as well as the response to a loss of voltage and a degraded voltage test, shall include a single point verification that the trip occurs within the required time delay, as applicable.

A CHANNEL CALIBRATION is performed every 24 months for the undervoltage relay and every 18 months for the degraded voltage relay. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The Frequency is based on operating experience and is justified by the assumption of the calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis (Ref. 3).

REFERENCES

1. FSAR, Section 8.2.
2. FSAR, Chapter 14.2.
3. Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3).

ATTACHMENT 10.1 SMM CONTROLLED DOCUMENT TRANSMITTAL FORM

SITE MANAGEMENT MANUAL CONTROLLED DOCUMENT TRANSMITTAL FORM - PROCEDURES

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CONTROLLED DOCUMENT TRANSMITTAL FORM - PROCEDURES

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UPDATE FOR IP3 TECHNICAL REQUIREMENTS MANUAL

AFFECTED SECTION	REMOVE	INSERT
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Section 3.3-B	Revision 2 Pages 3.3.B-1 through 3.3.B-12	Revision 3 Pages 3.3.B-1 through 3.3.B-12

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3.7.A.2	2	3.7.A.2-1 through 3	08/24/2004
3.7.A.3	5	3.7.A.3-1 through 6	08/24/2004
3.7.A.4	3	3.7.A.4-1 through 3	08/24/2004
3.7.A.5	1	3.7.A.5-1 through 3	08/24/2004
3.7.A.6	1	3.7.A.6-1 through 2	08/24/2004
3.7.A.7	2	3.7.A.7-1 through 4	08/24/2004
3.7.B	2	3.7.B-1 through 17	08/24/2004
3.7.C	0	3.7.C-1 through 8	03/19/2001
3.7.D	0	3.7.D-1 through 2	03/19/2001
3.7.E	0	3.7.E-1 through 2	03/19/2001
3.8.A	0	3.8.A-1 through 5	03/19/2001
3.8.B	0	3.8.B-1 through 7	03/19/2001
3.8.C	1	3.8.C-1 through 10	08/24/2004
3.8.D	0	3.8.D-1 through 2	03/19/2001
3.9	0	3.9-1	03/19/2001
4.0	0	4.0-1	03/19/2001
5.0	4	5.0-1 through 7	08/24/2004

3.3 INSTRUMENTATION

3.3.B Meteorological Monitoring Instrumentation

TRO 3.3.B The Meteorological Monitoring Instrument Channel per Table 3.3.B-1 shall be OPERABLE.

APPLICABILITY: At all times.

---NOTE---

1. TRO 3.0.C is not applicable.
2. TRO 3.0.D is not applicable.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. The Meteorological Monitoring Instrument Channel is inoperable.	A.1	DEMONSTRATE the ability to obtain meteorological data, using IP-EP-510, <u>AND</u> ---------------------NOTE---------------------- Action A.2 is NOT required when IP3 control room meteorological display and/or strip chart recorder are the only inoperable equipment. ---	1 hour
	A.2	Notify IP2 of system inoperability, <u>AND</u>	1 hour
	A.3	Restore the inoperable Meteorological Instrument Channel to OPERABLE status.	7 days
B. Required Actions and associated Completion Times of Condition A.3 not met.	B.1	Prepare and submit a Special Report to the On-Site Safety Review Committee outlining the actions taken, the cause of the inoperability and the plans for restoring the meteorological monitoring instrumentation channel(s) to OPERABLE status.	10 days

(continued)

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
TRS 3.3.B.1	---NOTE--- Control Room display on the back of the Flight Panel and the Meteorological Strip Chart Recorder are not required to meet the TRO. --- Perform CHANNEL CHECK.	24 hours
TRS 3.3.B.2	---NOTE--- This surveillance is not required to be performed to meet the TRO. --- Perform calibration of meteorological strip chart recorder.	24 months
TRS 3.3.B.3	---NOTE--- This surveillance is not required to be performed to meet the TRO when primary power source is available. --- DEMONSTRATE Meteorological Diesel Generator OPERABILITY by starting and running for 15 minutes.	31 days
TRS 3.3.B.4	---NOTE--- This surveillance is not required to be performed to meet the TRO when primary power source is available. --- DEMONSTRATE Diesel Generator Automatic Power Transfer by simulating power loss.	12 months
TRS 3.3.B.5	Perform CHANNEL CALIBRATION.	184 days
TRS 3.3.B.6	Perform CHANNEL OPERATIONAL TEST.	184 days

(continued)

TABLE 3.3.B-1

Meteorological Monitoring Instrumentation Channels

Instrument Channels	Instrument Channel Minimum Accuracies	Minimum Operable Channels
1. WIND SPEED[1] A. 10m	± 0.5 mph	1
2. WIND DIRECTION[1] A. 10m	± 5°	1
3. ATMOSPHERIC STABILITY (PASQUILL CATEGORY)[2] A. 60 - 10m	± 0.1°C for temperature inputs	1

Note 1 The 60m and 122m level instruments are not required to meet the TRO but are maintained to support Indian Point 2 requirements.

Note 2 The 122-10m delta temperature instruments are not required to meet the TRO but are maintained to support Indian Point 2 requirements.

BASES

BACKGROUND

The meteorological monitoring instrumentation system was installed to meet the requirements, in part, of 10 CFR 50 Appendix A (Reference 1), 10 CFR 50 Appendix E (Reference 2), and 10 CFR 50.47(b)(9) (Reference 3). These sections require that adequate methods, systems, and equipment for assessing and monitoring actual or potential offsite consequences of a radiological emergency be available.

Guidance on the meteorological monitoring requirements is provided in NUREG-0737 (Reference 4), NUREG-0654 (Reference 5), Regulatory Guide 1.23 (Reference 6), and Regulatory Guide 1.97 (Reference 7).

NUREG-0737 required that each nuclear facility "upgrade its emergency plans to provide reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency. Specific criteria to meet this requirement is delineated in NUREG-0654." NUREG-0737 also provided a schedule of implementation milestones to be met in order to address the introduction of NUREG-0654, Appendix 2. Letter IPN-80-117 (Reference 8) addressed each item of NUREG-0737 that was applicable to Indian Point 3 (IP3) and which had not been previously identified as complete. IP3 agreed to the staged implementation schedule required by the NUREG in this letter.

NUREG-0654 was issued, in part, to provide a basis for the development of radiological emergency plans and the improvement of emergency preparedness. Appendix 2 of NUREG-0654 states that "the emergency facilities and equipment as stated in Appendix E to 10 CFR Part 50 shall include '(E)quipment for determining the magnitude of and for continuously assessing the impact of the release of radioactive materials to the environment.' To address this requirement, in part, the nuclear power plant operator shall have meteorological measurements from primary and backup systems. Each site ... shall have a primary meteorological measurements system. The primary system shall produce current and record historical local meteorological data ... The acceptance criteria for meteorological measurements are described in the proposed Revision 1 to U.S. NRC Regulatory Guide 1.23."

Regulatory Guide (RG) 1.23 provides information on meteorological instrument accuracy and meteorological instrument maintenance and servicing schedules. The meteorological instrument accuracies are listed in Table 3.3.B-1. The guidance from RG 1.23 section C.4 and C.5 on meteorological maintenance and servicing schedules is reflected in the "Surveillance Requirements" section of this Technical Requirement.

(continued)

RG 1.97 describes a method for complying with the NRC's regulations to provide instrumentation to monitor, display and record plant variables and systems during and following an accident. Table 3 of the RG lists meteorological variables and the minimum ranges these variables should operate within. In addition, RG 1.97 stated that information gathered by these parameters "may be continually updated, stored in computer memory, and displayed on demand. Intermittent displays such as data loggers and scanning recorders may be used if no significant transient response information is likely to be lost by such a device."

The NRC issued a Confirmatory Order (Reference 9), requiring that IP3 perform certain additional actions to increase the margin of public health and safety. Included in the Order were a number of interim measures that pertained to the meteorological program and to Control Room instrumentation. Annex 1 to the Order laid out the meteorological acceptance criteria for emergency preparedness. The Annex essentially described the meteorological program as found in NUREG-0654 and added additional acceptance criteria from NUREG-75/087 section 2.3.3 (Reference 10).

NUREG-75/087, section 2.3.3 states that "Generally, the onsite meteorological programs must produce data which can be summarized to provide an adequate meteorological description of the site and its vicinity for the purpose of making atmospheric diffusion estimates for accidental and routine airborne releases of effluents. Guidance on an adequate program is given in Regulatory Guide 1.23."

IP3's response to the Confirmatory Order, letter IPN-80-77 (Reference 11), was to perform a detailed review of the meteorological program. The results of the review were that IP3 and IP2 complied with the Annex 1 meteorological criteria.

The NRC issued Generic Letter (GL) 82-33 (Reference 12) as a supplement to NUREG-0737. One purpose of the letter was to provide additional clarification regarding the application of RG 1.97 to emergency response facilities. In addition, the letter required licensees to evaluate how their post-accident monitoring instrumentation in the Control Room met the content of RG 1.97. Letter IPN-86-05 (Reference 13) outlined the status of IP3's compliance with RG 1.97 (e.g., the actual ranges that the meteorological variables should operate in and IP3's compliance with the requirements for data recording). The letter indicated that IP3 met the data recording requirements and also included the actual variable ranges used by the plant.

(continued)

The meteorological variable ranges required by the RG are as follows:

Wind Direction	required: 0 to 360°
Wind Speed	required: 0 to 50 mph
Atmospheric Stability (for Temperature inputs)	*required: -5 to 10°C

*Note: The actual range (-4.44 to 11°C) was deemed acceptable.

NRC Inspection Report 85-17 (Reference 14) documented a conversation between the NRC and IP3. During the conversation, the NRC stated that "Unit 2 technical specifications require that meteorological monitoring instrumentation channels be operable at all times with indication of the tabulated parameters available in the control room." As a result, the Authority stated that a method would be instituted to verify the readouts in the control room as well as at the meteorological tower. NRC Inspection Report No. 87-23 (Reference 15) closed this unresolved item. In this Inspection Report, the NRC stated, "The licensee has installed a meteorological tower display in the control room demand metering panel. The panel displays wind speed, wind direction, Pasquill category and the time of the last data update. The inspector reviewed Nuclear Safety Evaluation 87-03-049 INST, Rev. 0 for the modification."

In 1991, the NRC issued a Safety Evaluation (Reference 16) which re-evaluated IP3's conformance to RG 1.97. The evaluation was performed as a follow-up to determine if and how we were conforming to the contents of GL 82-33. Contained in this evaluation was the NRC's conclusion that "... the licensee (IP-3) has provided an explicit commitment on conformance to RG 1.97."

NRC Inspection Report 92-17 (Reference 17) documented an inspection involving IP3's Radiological Environmental Monitoring Program. The purpose of the inspection, in part, was to review the "meteorological monitoring program to determine whether the instrumentation and equipment were operable, calibrated and maintained in accord with licensee's requirements ... Based on the review of the program and discussions with the licensee's representatives, the inspector determined that overall the licensee has implemented an effective Meteorological Monitoring Program."
In addition to the above NRC commitments, IP3 will comply with the requirements of other outside agencies. These agencies include the Federal Aviation Administration, Environmental Protection Agency, etc.

APPLICABLE SAFETY ANALYSES

The meteorological system is described in FSAR chapter 2.6 (Reference 18), Emergency Plan Procedure, IP-EP-510, "Meteorological, Radiological & Plant Data Acquisition System" (Reference 19), and Nuclear Safety Evaluation 87-03-049 INST (Reference 20). The meteorological measurements program consists of primary and backup systems. The primary system consists of a 122m instrumented tower which provides measurements for wind speed and wind direction at a minimum of two levels, one of which is representative of the 10 meter level. Data obtained from the 10m elevation of the meteorological tower is transmitted through a computer system to a meteorological LED display panel in the Control Room. IP3 maintains responsibility of the Meteorological Monitoring Program, except for the Meteorological Computer System, which is the responsibility of IP2. The meteorological tower display indicates wind speed, wind direction, Pasquill Category and the time of the last update. The output to the LED display panel is the result of a fifteen minute average of computated data from the Meteorological Computer System. The LEDs are updated every fifteen minutes. Also located in the control room is a two-pen variable trend recorder (strip chart) which is used to trend wind speed and wind direction. The data displayed represents a 15-minute average.

In the event of a power outage, a diesel generator has been installed to provide immediate power to the meteorological tower system.

In the event of a failure of the primary meteorological measurement system, a backup meteorological system is used. Changeover from the primary system to the backup system occurs automatically.

This system is independent of the primary system and consists of two instrumented meteorological towers, a primary backup tower and a standby backup tower. The backup meteorological tower records wind direction and speed measurements at the 10m level. The backup system provides information in the real-time mode. In the event of primary power failure, power is supplied for six days by a battery located adjacent to the tower. In the event of a failure of the backup meteorological measurement system, changeover from the backup system to the standby system is accomplished manually.

(continued)

TRO

The Meteorological Monitoring Instrument Channel must be OPERABLE to allow adequate assessing, monitoring and recording of actual or potential offsite consequences of a radiological emergency.

An OPERABLE Meteorological Monitoring Instrument Channel constitutes the following:

1. Instrumentation on the primary meteorological tower for providing wind direction and speed measurement, representative of the 10m level per Table 3.3.B-1, shall be OPERABLE.

2. The Meteorological Computer System shall be OPERABLE.

3. Power supply is available. A power supply must be available from the normal power supply or the meteorological diesel generator.

APPLICABILITY

The Meteorological Monitoring Instrumentation Channel are required to be OPERABLE at all times.

ACTIONS

A.1

The meteorological monitoring instrumentation was installed to meet the requirements of NUREG-0737 Section III.A.2.2. The operation of this equipment is also described in the IPEC Emergency Plan, stating that the Meteorological Monitoring Instrumentation Channel meets the requirements for indication and remote access. The channel is required in order to comply with the requirements of RG 1.97 which requires "the instrumentation signal may be displayed on an individual instrument or it may be processed for display on demand. Signals from meteorology monitors should be recorded. For recording, it may be continuously updated, stored in computer memory and displayed on demand."

A Meteorological Monitoring Instrument Channel would be required for determining the magnitude if and for continuously assessing the impact of the release of radioactive materials to the environment.

With the meteorological monitoring instrumentation channel inoperable, the backup meteorological monitoring instrumentation channel(s) must be DEMONSTRATED OPERABLE within 1 hour. DEMONSTRATION shall be achieved using Emergency Plan Procedure IP-EP-510, which describes the means to obtain meteorological data.

(continued)

A.2

With the meteorological monitoring instrumentation channel inoperable, IP2 shall be notified within 1 hour. This notification is not required for IP3 control room display and/or recorder inoperability as this equipment does not directly impact IP2.

A.3

With the meteorological monitoring instrumentation channel inoperable, the channel must be restored to OPERABLE status within 7 days. The meteorological monitoring instrumentation channel(s) would be required in the event of a radiological emergency.

The allowable outage time (AOT) of 7 days, which is specified by this Action, was developed, in part, by taking into consideration former Westinghouse Standard Technical Specifications section 3.3.3.4 (Reference 21) which specified a 7 day time frame. In addition, consideration was given to IP2's Technical Requirements Manual section 3.3.A (Reference 22) which also specifies an AOT of 7 days.

B.1

This Action shall be taken if the Required Actions and associated Completion Times of Condition A have not been met. A Special Report shall be prepared and submitted to the On-Site Safety Review Committee outlining the cause of the malfunction and the plans for restoring the meteorological monitoring instrumentation channel(s) to OPERABLE status. This reporting is necessary to ensure oversight for restoring the OPERABILITY of the Meteorological Monitoring Instrument Channel and the collection of meteorological data at the plant site. This data is used for estimating potential radiation doses to the public resulting from routine or accidental releases of radioactive materials to the atmosphere.

A meteorological data collection program, as described in this technical requirement, is necessary to meet the requirements of 10 CFR 50.36a(a)(2), Appendix E to 10 CFR 50 and 10 CFR 51.

The ten-day period for preparing and submitting the Special Report was developed by taking into consideration IP2 Technical Requirements Manual section 3.3.A. This section requires that with one or more of the required meteorological monitoring channels inoperable for more than seven (7) days, prepare and submit to the On-Site Safety Review Committee within the next 10 days . . . a Corrective Action Report . . . outlining the cause of the malfunction(s) and the plans for restoring the channel(s) to operable status.

SURVEILLANCE REQUIREMENTS

TRS 3.3.B.1

The performance of daily CHANNEL CHECKs is required to meet a commitment to the NRC. IP3 committed to daily CHANNEL CHECKs via a telephone conversation with the NRC (on August 12, 1985). The NRC acknowledged this verbal commitment in Inspection Report 85-17. Inspection Report 85-17 documented the conversation in which the NRC stated that Indian Point Unit 2 Technical Specifications (now Technical Requirements Manual) contain the requirement that "meteorological monitoring instrumentation channels be operable at all times with indication of the tabulated parameters available in the control room. Furthermore, the IP2 Technical Specifications also require a daily CHANNEL CHECK of the meteorological monitoring instrumentation and states that 'each meteorological monitoring channel shall be demonstrated operable' (T.S. 4.19.A)." As a result, IP3 agreed that the IP3 control room instrumentation should be DEMONSTRATED OPERABLE by a daily CHANNEL CHECK.

TRS 3.3.B.2

Based on engineering judgement, IP3 has concluded that the 24 month calibration interval of the meteorological strip chart recorder is adequate.

TRS 3.3.B.3

Based on engineering judgement, IP3 has concluded that monthly testing is adequate to demonstrate the OPERABILITY of the meteorological diesel generator.

TRS 3.3.B4

Based on engineering judgement, IP3 has concluded that annual testing is adequate to DEMONSTRATE diesel generator automatic power transfer.

TRS 3.3.B.5

The performance of semiannual instrument CHANNEL CALIBRATION is required to satisfy RG 1.23 section C.5. Compliance with RG 1.23 section C.5 is required per the NRC's February 11, 1980 Confirmatory Order. Section C.5 stated that meteorological "instruments should be calibrated at least semiannually." In addition, this calibration frequency is consistent with TRS 3.3.A.1 and TRS 3.3.A.2 of IP2's Technical Requirements Manual.

(continued)

TRS 3.3.B.6

The performance of semiannual instrument CHANNEL OPERATIONAL TEST ensures the signal is being delivered through the instrument channel. The frequency is chosen to be consistent with the frequency for instrument CHANNEL CALIBRATION.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50 Appendix A, Criterion 64, "Monitoring Radioactivity Releases."

2. Title 10, Code of Federal Regulations, Part 50 Appendix E, Section E, "Emergency Facilities and Equipment."

3. Title 10, Code of Federal Regulations, Part 50.47, "Emergency Plans."

4. NUREG-0737, "Clarification of TMI Action Plans Requirements."

5. NUREG-0654/FEMA, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Appendix 2, "Meteorological Criteria for Emergency Preparedness at Operating Nuclear Power Plants."

6. Regulatory Guide 1.23, "Onsite Meteorological Programs."

7. NRC Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident."

8. NYPA Letter IPN-80-117, J. P. Bayne to D. G. Eisenhut, dated December 30, 1980, "Post TMI Requirements."

9. NRC Confirmatory Order, H. R. Denton to E. R. Weiss, dated February 11, 1980.

10. NUREG-75/087, "Standard Review Plan."

11. NYPA Letter IPN-80-77, G. M. Wilverding to S. A. Varga, dated August 11, 1980, "Confirmatory Order (Interim Actions) Six Month Responses."

(continued)

12. Generic Letter 82-33, dated December 17, 1982, "Supplement 1 to NUREG-0737 - Requirements for Emergency Response Capability."

13. NYPA Letter IPN-86-05, J. C. Brons to S. A. Varga, dated January 7, 1986, "Regulatory Guide 1.97 Implementation Program."

14. NRC Inspection Report No. 50-286/85-17, Section 7.0, T. T. Martin to W. Josiger, dated August 22, 1985, "Implementation of the Meteorological Monitoring Program."

15. NRC Inspection Report No. 50-286/87-23, E. C. Wenzinger to W. Josiger, dated October 15, 1987.

16. NRC Safety Evaluation, J. D. Neighbors to R. E. Beedle, dated April 3, 1991, "Emergency Response Capability - Conformance to Regulatory Guide 1.97, Revision 3, for Indian Point 3."

17. NRC Inspection Report No. 50-286/92-17, J. H. Joyner to J. E. Russell, dated July 18, 1992.

18. Indian Point 3 FSAR, Section 2.6.5, "Onsite Meteorological Measurements Program."

19. Emergency Plan Procedure, IP-EP-510, "Meteorological, Radiological & Plant Data Acquisition System."

20. Nuclear Safety Evaluation NSE 87-03-049 INST, "Control Room Meteorological Display Upgrade."

21. NUREG-1431, Westinghouse Standard Technical Specifications section 3.3.3.4, "Meteorological Instrumentation."

22. Unit 2 Technical Requirements Manual Section 3.3.B "Meteorological Monitoring."

TRO

The Meteorological Monitoring Instrument Channel must be OPERABLE to allow adequate assessing, monitoring and recording of actual or potential offsite consequences of a radiological emergency.

An OPERABLE Meteorological Monitoring Instrument Channel constitutes the following:

1. Instrumentation on the primary meteorological tower for providing wind direction and speed measurement, representative of the 10m level per Table 3.3.B-1, shall be OPERABLE.

2. The Meteorological Computer System shall be OPERABLE.

3. Power supply is available. A power supply must be available from the normal power supply or the meteorological diesel generator.

APPLICABILITY

The Meteorological Monitoring Instrumentation Channel are required to be OPERABLE at all times.

ACTIONS

A.1

The meteorological monitoring instrumentation was installed to meet the requirements of NUREG-0737 Section III.A.2.2. The operation of this equipment is also described in the IPEC Emergency Plan, stating that the Meteorological Monitoring Instrumentation Channel meets the requirements for indication and remote access. The channel is required in order to comply with the requirements of RG 1.97 which requires "the instrumentation signal may be displayed on an individual instrument or it may be processed for display on demand. Signals from meteorology monitors should be recorded. For recording, it may be continuously updated, stored in computer memory and displayed on demand."

A Meteorological Monitoring Instrument Channel would be required for determining the magnitude if and for continuously assessing the impact of the release of radioactive materials to the environment.

With the meteorological monitoring instrumentation channel inoperable, the backup meteorological monitoring instrumentation channel(s) must be DEMONSTRATED OPERABLE within 1 hour. DEMONSTRATION shall be achieved using Emergency Plan Procedure IP-EP-510, which describes the means to obtain meteorological data.

(continued)

A.2

With the meteorological monitoring instrumentation channel inoperable, IP2 shall be notified within 1 hour. This notification is not required for IP3 control room display and/or recorder inoperability as this equipment does not directly impact IP2.

A.3

With the meteorological monitoring instrumentation channel inoperable, the channel must be restored to OPERABLE status within 7 days. The meteorological monitoring instrumentation channel(s) would be required in the event of a radiological emergency.

The allowable outage time (AOT) of 7 days, which is specified by this Action, was developed, in part, by taking into consideration former Westinghouse Standard Technical Specifications section 3.3.3.4 (Reference 21) which specified a 7 day time frame. In addition, consideration was given to IP2's Technical Requirements Manual section 3.3.A (Reference 22) which also specifies an AOT of 7 days.

B.1

This Action shall be taken if the Required Actions and associated Completion Times of Condition A have not been met. A Special Report shall be prepared and submitted to the On-Site Safety Review Committee outlining the cause of the malfunction and the plans for restoring the meteorological monitoring instrumentation channel(s) to OPERABLE status. This reporting is necessary to ensure oversight for restoring the OPERABILITY of the Meteorological Monitoring Instrument Channel and the collection of meteorological data at the plant site. This data is used for estimating potential radiation doses to the public resulting from routine or accidental releases of radioactive materials to the atmosphere.

A meteorological data collection program, as described in this technical requirement, is necessary to meet the requirements of 10 CFR 50.36a(a)(2), Appendix E to 10 CFR 50 and 10 CFR 51.

The ten-day period for preparing and submitting the Special Report was developed by taking into consideration IP2 Technical Requirements Manual section 3.3.A. This section requires that with one or more of the required meteorological monitoring channels inoperable for more than seven (7) days, prepare and submit to the On-Site Safety Review Committee within the next 10 days . . . a Corrective Action Report . . . outlining the cause of the malfunction(s) and the plans for restoring the channel(s) to operable status.

SURVEILLANCE REQUIREMENTS

TRS 3.3.B.1

The performance of daily CHANNEL CHECKs is required to meet a commitment to the NRC. IP3 committed to daily CHANNEL CHECKs via a telephone conversation with the NRC (on August 12, 1985). The NRC acknowledged this verbal commitment in Inspection Report 85-17. Inspection Report 85-17 documented the conversation in which the NRC stated that Indian Point Unit 2 Technical Specifications (now Technical Requirements Manual) contain the requirement that "meteorological monitoring instrumentation channels be operable at all times with indication of the tabulated parameters available in the control room. Furthermore, the IP2 Technical Specifications also require a daily CHANNEL CHECK of the meteorological monitoring instrumentation and states that 'each meteorological monitoring channel shall be demonstrated operable' (T.S. 4.19.A)." As a result, IP3 agreed that the IP3 control room instrumentation should be DEMONSTRATED OPERABLE by a daily CHANNEL CHECK.

TRS 3.3.B.2

Based on engineering judgement, IP3 has concluded that the 24 month calibration interval of the meteorological strip chart recorder is adequate.

TRS 3.3.B.3

Based on engineering judgement, IP3 has concluded that monthly testing is adequate to demonstrate the OPERABILITY of the meteorological diesel generator.

TRS 3.3.B4

Based on engineering judgement, IP3 has concluded that annual testing is adequate to DEMONSTRATE diesel generator automatic power transfer.

TRS 3.3.B.5

The performance of semiannual instrument CHANNEL CALIBRATION is required to satisfy RG 1.23 section C.5. Compliance with RG 1.23 section C.5 is required per the NRC's February 11, 1980 Confirmatory Order. Section C.5 stated that meteorological "instruments should be calibrated at least semiannually." In addition, this calibration frequency is consistent with TRS 3.3.A.1 and TRS 3.3.A.2 of IP2's Technical Requirements Manual.

(continued)

TRS 3.3.B.6

The performance of semiannual instrument CHANNEL OPERATIONAL TEST ensures the signal is being delivered through the instrument channel. The frequency is chosen to be consistent with the frequency for instrument CHANNEL CALIBRATION.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50 Appendix A, Criterion 64, "Monitoring Radioactivity Releases."
2. Title 10, Code of Federal Regulations, Part 50 Appendix E, Section E, "Emergency Facilities and Equipment."
3. Title 10, Code of Federal Regulations, Part 50.47, "Emergency Plans."
4. NUREG-0737, "Clarification of TMI Action Plans Requirements."
5. NUREG-0654/FEMA, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Appendix 2, "Meteorological Criteria for Emergency Preparedness at Operating Nuclear Power Plants."
6. Regulatory Guide 1.23, "Onsite Meteorological Programs."
7. NRC Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident."
8. NYPA Letter IPN-80-117, J. P. Bayne to D. G. Eisenhut, dated December 30, 1980, "Post TMI Requirements."
9. NRC Confirmatory Order, H. R. Denton to E. R. Weiss, dated February 11, 1980.
10. NUREG-75/087, "Standard Review Plan."
11. NYPA Letter IPN-80-77, G. M. Wilverding to S. A. Varga, dated August 11, 1980, "Confirmatory Order (Interim Actions) Six Month Responses."

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12. Generic Letter 82-33, dated December 17, 1982, "Supplement 1 to NUREG-0737 - Requirements for Emergency Response Capability."

13. NYPA Letter IPN-86-05, J. C. Brons to S. A. Varga, dated January 7, 1986, "Regulatory Guide 1.97 Implementation Program."

14. NRC Inspection Report No. 50-286/85-17, Section 7.0, T. T. Martin to W. Josiger, dated August 22, 1985, "Implementation of the Meteorological Monitoring Program."

15. NRC Inspection Report No. 50-286/87-23, E. C. Wenzinger to W. Josiger, dated October 15, 1987.

16. NRC Safety Evaluation, J. D. Neighbors to R. E. Beedle, dated April 3, 1991, "Emergency Response Capability - Conformance to Regulatory Guide 1.97, Revision 3, for Indian Point 3."

17. NRC Inspection Report No. 50-286/92-17, J. H. Joyner to J. E. Russell, dated July 18, 1992.

18. Indian Point 3 FSAR, Section 2.6.5, "Onsite Meteorological Measurements Program."

19. Emergency Plan Procedure, IP-EP-510, "Meteorological, Radiological & Plant Data Acquisition System."

20. Nuclear Safety Evaluation NSE 87-03-049 INST, "Control Room Meteorological Display Upgrade."

21. NUREG-1431, Westinghouse Standard Technical Specifications section 3.3.3.4, "Meteorological Instrumentation."

22. Unit 2 Technical Requirements Manual Section 3.3.B "Meteorological Monitoring."

Exhibit EE

Exhibit "EE"

U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation

NRR OFFICE INSTRUCTION

Change Notice

Office Instruction No.:	**LIC-100**
Office Instruction Title:	**Control of Licensing Bases for Operating Reactors**
Office Instruction Revision No.:	**00-a**
Effective Date:	**March 2, 2001**
Primary Contacts:	**William Reckley** **301-415-1323** **wdr@nrc.gov**
Responsible Organization:	**NRR/DLPM/LPD4**

Summary of Changes: This is the initial issuance of LIC-100, "Control of Licensing Bases for Operating Reactors" (previously NRR Office Letter 807). Changes to the guidance include minor corrections and suggested clarifications offered by NRR staff and external stakeholders. No significant policy or procedural changes have been made to the guidance document.

Training:	E-mail announcement with recommended self-study
ADAMS Accession No.:	**ML010660227**

Position	Primary Contact	Responsible Manager	ODNRR
Name	WReckley	SRichards	SCollins
Date	2/6/01; 2/28/01	3/ 1/01	3/02 /01

OFFICIAL RECORD COPY

NRR OFFICE INSTRUCTION
LIC-100
Revision 00-a

Control of Licensing Bases for Operating Reactors

1. POLICY

It is the policy of NRR to make decisions regarding the addition of, removal of, or changing of specific aspects of the licensing bases of nuclear power plants with appropriate consideration given to the limitations and advantages of the various types (or elements) of licensing bases information. The purpose of this instruction is to ensure that interactions between the staff, licensees, and other parties are conducted with mutual understanding of the terminology and characteristics of various documents that make up the licensing bases for an operating nuclear power plant.

2. OBJECTIVES

This office instruction, along with the attached guidance document, provides all staff in the NRC's Office of Nuclear Reactor Regulation (NRR) a basic framework for making decisions about creating, revising or deleting licensing bases information for operating power reactors.

These procedures should enhance NRR's efficiency in responding to the needs of both the licensees and the public. Specific objectives include the following:

- Ensure the effective use of NRC's regulatory processes maintains the public health and safety

- Promote public confidence in NRC licensing processes by establishing a common reference, an understandable framework for licensing bases decisions, and a common understanding of roles, responsibilities, and opportunities for participation

- Reduce unnecessary regulatory burdens by establishing a common understanding of the control of licensing bases and by promoting the use of the most appropriate licensing process to achieve the desired results

- Increase the effectiveness, efficiency, and realism of nuclear licensing by establishing a common reference for processes, communications, and decision-making.

The attached "Guideline for Managing the Licensing Bases for Operating Reactors" provides a general description of various attributes of the elements of the licensing bases for operating reactors.

3. BACKGROUND

NRR Office Letter 807, "Control of Licensing Bases for Operating Reactors," was issued on April 5, 2000. The guide attached to the office letter was issued in draft form to allow for suggestions, corrections, and other feedback from NRR staff and agency stakeholders. Several comments and suggestions were received between issuance of Office Letter 807 and the conversion of the guidance into this office instruction. The changes made as a result of the comments involved editorial corrections and clarifications. Additional changes reflect the issuance in late 2000 of Regulatory Guide 1.187, "Guidance for Implementation of 10 CFR 50.59, 'Changes, Tests and Experiments'," and Regulatory Guide 1.186, "Guidance and Examples for Identifying 10 CFR 50.2 Design Basis."

4. BASIC REQUIREMENTS

The attached guidance describes the general structure of the licensing bases for operating reactors in terms of elements and various characteristics or attributes for the elements. The managers and staff of NRR should understand the attributes of those elements of the licensing bases in which they play a primary or supporting role.

The managers and staff of NRR should consider the best ways to achieve the stated goals of the agency and office. This includes revising the elements as necessary, including changing regulations, as well as revising the internal and external processes associated with controlling each element. The staff should process changes to the licensing bases for specific operating plants in accordance with available guidance in support of agency and office performance goals.

5. RESPONSIBILITIES AND AUTHORITIES

Branch Chiefs and Project Directors

Branch chiefs and project directors are responsible for the programmatic control of individual elements of the licensing bases (e.g., technical specifications and emergency preparedness plan) and attributes of elements of the licensing bases (e.g., change-control and reporting). This responsibility includes providing sufficient guidance to ensure the effective and efficient control of the licensing bases elements by the staff, the licensees, and the public.

Branch chiefs and project directors also have the responsibility to ensure that the routine control of the licensing bases for individual plants is performed such that we maintain safety, reduce unnecessary regulatory burden, increase effectiveness, efficiency and realism of NRC processes, and increase public confidence.

Section Chiefs

Section chiefs are responsible for assigning and managing specific work items for docket-specific tasks and in some cases are responsible for the maintenance, revision, and implementation of programs for specific elements of the licensing bases.

Project Managers

Project managers generally coordinate NRR staff efforts for an assigned facility, a generic issue, or a policy issue to ensure that the outputs are complete, accurate, and timely. Project managers coordinate the work planning within NRR and, as necessary, with other offices. Project managers serve as the point of contact with licensees for assigned facilities. Project managers resolve or escalate conflicts within the staff or between the staff and stakeholders such that technical issues are resolved in a timely and professional manner. Project managers are generally responsible for managing the licensing agenda for assigned facilities and resolving issues about licensing bases for assigned facilities.

Office of the General Counsel (OGC)

OGC plays a critical role in defining the elements of the licensing bases, defining the appropriate controls for and other attributes of the elements of the licensing bases, and in processing some plant-specific changes to licensing bases information. The staff and management of NRR should coordinate their programmatic and plant-specific efforts with OGC in order to ensure their products comply with legal requirements and to ensure that OGC concerns are resolved in a timely manner.

6. PERFORMANCE MEASURES

No performance measures specifically for this office instruction.

7. PRIMARY CONTACT

William Reckley
NRR/DLPM
301-415-1323
wdr@nrc.gov

8. RESPONSIBLE ORGANIZATION

NRR/DLPM/LPD4

9. EFFECTIVE DATE

March 2, 2001

10. REFERENCES

Appendix A: CHANGE HISTORY

Appendix B: GUIDELINE FOR MANAGING THE LICENSING BASES FOR OPERATING REACTORS

Appendix A - Change History

Office Instruction LIC-100, "Control of Licensing Bases for Operating Reactors"

	ADM-100 Change History - Page 1 of 1				
Revision		**Date**	**Description of Changes**	**Method Used to Announce & Distribute**	**Training**
No.	**Ltr**				
00	a	03/02/01	Initial Issuance	E-mail to all staff	Appropriate self-study; as instructed by first-line supervisor Training Module on NRC Internal Home Page; Program Offices - NRR http://nrr10.nrc.gov/nrrhome.htm **charge training to TAC MB0995**

GUIDELINE FOR MANAGING THE LICENSING BASES FOR OPERATING REACTORS

OFFICE OF NUCLEAR REACTOR REGULATION
U.S. NUCLEAR REGULATORY COMMISSION
MARCH 2001

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1 Introduction

The licensing bases for a commercial nuclear power plant is comprised of selected information exchanged between a licensee and the NRC. The information is related to design features, equipment descriptions, operating practices, site characteristics, programs and procedures, and other factors that describe a plant's design, construction, maintenance, and operation. The information is contained in a variety of document types. Each document has certain characteristics in terms of change control mechanisms, reporting of changes to the NRC, the mechanisms for dealing with discrepancies, and the possible involvement of the public. This guidance document will detail the major elements of a nuclear plant's licensing bases and discuss the important characteristics of each element. The purpose of this guidance is to ensure that interactions between the staff, licensees, and other parties are conducted with mutual understanding of the terminology as well as the characteristics of various documents. The NRC staff should make sure that decisions regarding the addition of, removal of, or changing of specific aspects of the licensing bases of a nuclear power plant are made with appropriate consideration given to the limitations and advantages of the various types (or elements) of licensing bases information.[1]

Although the terms "current licensing bases" and "licensing bases" are widely used in matters related to power reactors operating in accordance with the regulations in 10 CFR Part 50, the terms are not defined in Part 50 or major regulatory guidance related to Part 50. The following definition is provided by 10 CFR 54.3 pertaining to license renewal for power reactor facilities.

> Current licensing basis (CLB) is the set of NRC requirements applicable to a specific plant and a licensee's written commitments for ensuring compliance with and operation within applicable NRC requirements and the plant-specific design basis (including all modifications and additions to such commitments over the life of the license) that are docketed and in effect. The CLB includes the NRC regulations contained in 10 CFR Parts 2, 19, 20, 21, 26, 30, 40, 50, 51, 54, 55, 70, 72, 73, 100 and appendices thereto; orders; license conditions; exemptions; and technical specifications. It also includes the plant-specific design-basis information defined in 10 CFR 50.2 as documented in the most recent final safety analysis report (FSAR) as required by 10 CFR 50.71 and the licensee's commitments remaining in effect that were made in docketed licensing correspondence such as licensee responses to NRC bulletins, generic letters, and enforcement actions, as well as licensee commitments documented in NRC safety evaluations or licensee event reports.

Establishing a common understanding of the existing licensing bases and related processes is especially important to our efforts to make significant revisions to the NRC's regulatory approach. Improvements in this area are necessary as the NRC measures its performance

[1] This guidance document provides general instruction and standard practices. The staff should ensure that specific situations are addressed in accordance with applicable regulations, policies, and procedures. Questions regarding a specific situation should, as necessary, be directed to NRR subject matter experts and the Office of the General Counsel.

not only in terms of maintaining safety, but also in how it accomplishes that objective. The NRC has established performance goals that include decreasing unnecessary regulatory burden, improving public confidence in our licensing and oversight functions, and making our processes more effective, efficient, and realistic. Revising long-standing requirements and technical positions requires that we understand the complicated nature of how the licensing bases for power reactors has evolved over several decades. Establishing a common understanding of the various elements of the licensing bases for operating reactors can help in deciding how best to change the licensing bases for large or small sets of licensees. For example, introducing new change-control and reporting mechanisms may be an alternative to developing new technical requirements.

This guidance document focuses on the processes and procedures for controlling or revising licensing bases information. The evolution of specific technical positions and requirements has also been complicated. Reference documents such as the NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," and NUREG-1412, "Foundation for the Adequacy of the Licensing Bases," may be useful in researching the technical bases for NRC positions. In some cases, plant specific research may be the only way to establish the licensing bases for a particular issue. It can be especially difficult to find the rationale for technical positions taken in the licensing of older plants. The Systematic Evaluation Program (SEP) reviewed some older plants following the issuance of the standard review plan in the mid-1970's. Documents related to the SEP may be valuable plant specific references.

The licensing bases for a nuclear power reactor can be represented by a few categories of information that form a hierarchy structure in terms of associated change controls and reporting requirements. The approach to the hierarchy that is used in this instruction is as follows:

(1) Obligations - conditions or actions that are legally binding requirements imposed on licensees through applicable rules, regulations, orders, and licenses (including technical specifications and license conditions). The imposition of obligations (sometimes referred to as regulatory requirements) during routine interactions with licensees should be reserved for matters that satisfy the criteria of 10 CFR 50.36 or are otherwise found to be of high safety or regulatory significance. The major distinction between obligations and other parts of the licensing bases is that changes generally cannot be made without prior NRC approval.

(2) Mandated Licensing Bases Documents - documents, such as the updated FSAR, the quality assurance program, the security plan, and the emergency plan, for which the NRC has established requirements for content, change control and reporting. What information should be included in these documents is specified in applicable regulations and regulatory guides. The change control mechanisms and reporting requirements are defined by regulations such as 10 CFR 50.59, 50.54, and 50.71.

(3) Regulatory Commitments - explicit statements to take a specific action agreed to, or volunteered by, a licensee and submitted in writing on the docket to the NRC. A regulatory commitment is appropriate for matters in which the staff has a significant interest but which do not warrant either a legally binding requirement or inclusion in

the updated FSAR or a program subject to a formal regulatory change control mechanism. Control of such commitments in accordance with licensee programs is acceptable provided those programs include controls for evaluating changes and, when appropriate, reporting them to the NRC.

In addition to licensing bases information, a large amount of information is exchanged during routine interactions between the NRC staff and licensees that does not warrant being considered as part of the "licensing bases." Information provided to NRC staff in regional offices or headquarters pertaining to corrective actions for routine problems with plant equipment or procedures would likely fall into this category. The information should be controlled in accordance with normal licensee programs. There should be mutual understanding by licensees and NRC staff that such information may not need to be updated in docketed correspondence. The NRC staff's confidence that adequate controls are placed on the subject design or operating practice is usually provided by the applicability of general requirements such as Appendix B for quality assurance.

The major elements of the licensing bases of commercial reactors are discussed in the following sections. Each element is described in terms of several characteristics or attributes. These characteristics are defined below:

- Regulatory Bases: Many of the licensing bases elements have characteristics defined in specific regulations. For each element, the major ties to regulations are defined. For example, the content for FSARs to support initial licensing is contained in 10 CFR 50.34, while the need to maintain an updated FSAR is contained in 10 CFR 50.71.

- Location of licensing bases information: Each element has a document or location(s) where the licensing bases information is found. The various volumes of the updated FSAR are an example.

- Nonconformances and/or Unplanned Changes: Each element of the licensing bases has a process or common practice to deal with deviations, temporary changes, or nonconformances. The licensing bases for each reactor includes details on a corrective action program (through NRC regulations and NRC reviewed QA program). In general, the corrective action program addresses deviations and nonconformances with most elements of the licensing bases. NRC involvement in most of these situations is through the inspection, assessment, and enforcement programs. Provided the licensee is able to correct the problem and restore compliance, nonconformance or temporary deviations from the licensing bases are not addressed by a licensing-related process within NRR.

  Some elements of the licensing bases require NRC involvement for a plant to operate in nonconformance with a requirement. The most common example is the need to grant a notice of enforcement discretion (NOED) for a temporary and nonrecurring noncompliance with the requirements stated in the technical specifications.

Generic Letter 91-18, "Information to Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions," provides a useful bridge between the technical specifications and other licensing bases or design requirements on structures, systems, and components (SSCs). The generic letter and associated inspection manual material describes a process whereby a licensee evaluates degraded conditions to determine if the affected SSC remains operable (as defined and used in technical specifications). The guidance in GL 91-18 addresses those requirements placed on equipment beyond those specifically included in technical specifications. Such requirements include seismic and environmental qualification of equipment as well as common operational or preventive maintenance parameters such as temperatures, pressures, and flows. Provided that the SSC is considered operable, the licensee may continue operation (possibly with compensatory measures taken to address the degraded condition) without entering the action statements in the technical specifications.

- Planned or routine change control: Requirements or accepted practices for handling planned changes also exist for each element. For example, 10 CFR 50.59 and associated guidance documents define the criteria used to review changes to the facility as described in the updated FSAR to determine if the NRC must approve a change.

- Reporting to NRC staff: Requirements or accepted practices for reporting changes exist for each element. For example, 10 CFR 50.59 and 50.71(e) and associated guidance documents define the requirements for reporting changes to the facility and incorporating changes into the updated FSAR.

- Enforcement Practices: The NRC has mechanisms for interacting with licensees when it is found that a design feature or operating practice deviates from the licensing bases. Detailed guidance on possible enforcement actions or the use of other administrative tools is provided in the NRC Enforcement Manual.

- Verification and Monitoring: The NRC uses different mechanisms to verify or monitor licensee implementation and control over various elements of the licensing bases. An example is the inclusion in the NRC's inspection program of a module to assess each licensee's use of 10 CFR 50.59 for evaluating and reporting changes, tests and experiments. Information on how the licensing bases are monitored is usually provided in the NRC Inspection Manual.

- Public Involvement: The public is key stakeholder in the formulation and maintenance of the licensing bases for power reactors. Some of the elements have specific requirements for providing an opportunity for public comment or adjudication. The controls for most elements of the licensing bases rely on making information accessible to the public but do not actively solicit public comment on changes to the licensing bases information. The staff should use available guidance for interacting with licensees during meetings, correspondence, or other means to ensure transparency and promote public confidence. The staff should consider whether our goal of promoting public confidence in NRC's oversight of power reactors warrants special notifications, solicitation of comments, or other actions not specifically required by NRC regulations or procedures.

- Available Guidance Documents: Where they exist, the staff is referred to available guidance documents for controls to the various elements of the licensing bases.

A summary of the attributes for each major licensing bases element discussed in this guidance document is provided as Attachment 1. As previously stated, this guidance document provides general instruction and standard practices. The staff should ensure that specific situations are addressed in accordance with applicable regulations, policies, and procedures. Questions regarding a specific situation should, as necessary, be directed to NRR subject matter experts and the Office of the General Counsel. This caution is especially relevant to the summary table in Attachment 1.

During the course of reviewing or changing the licensing bases for a plant, the staff will occasionally discover a previous change that was not performed in accordance with the guidance in this instruction. The staff is not necessarily required to correct a situation where in the past we did not correctly revise the licensing bases. For example, if there was a case where the requirements of an order were revised by letters instead of by a license amendment or revised order, the staff may accept the previous changes to the licensing bases without issuing an order. If a convenient means of correcting a previous error is available (i.e., inclusion in a pending order or license amendment), the staff may use the ongoing licensing action to address the previous error.

Some licensing bases information is also addressed within multiple elements. Some overlap or duplication is unavoidable between documents such as the updated FSAR and technical specifications. The staff should, however, work to minimize the duplication of information in the various elements of the licensing bases. The control of the licensing bases is made more efficient and understandable if the number of change-control and reporting processes is minimized. The recent changes in 10 CFR 50.59 may facilitate the reductions in duplications given that the rule and associated guidance documents have addressed many perceived weaknesses or omissions in controlling some licensing bases information.

The inspection program and NRR licensing reviews have traditionally been fairly independent activities after the issuance of the operating license. It should be noted that in considering combinations of the various elements of the licensing bases, it is often possible to achieve equivalent regulatory requirements while shifting some of the oversight function from NRR licensing reviews to the NRC inspection program. An example would be reference to the quality assurance criteria in 10 CFR 50, Appendix B to provide confidence that a licensee will ensure certain safety-related equipment meets functional requirements in lieu of the NRR staff conducting a detailed review of the same proposal. The licensing bases, in terms of the relevant regulatory requirements and descriptions in the updated FSAR, will be very similar for the two approaches. Much of the information provided by a licensee to support the NRR review is ancillary information which is not incorporated into the set of actual licensing bases information for the subject facility. If NRR foregoes reviewing some of the details and instead references Appendix B or other regulatory requirements, some of the oversight function could be seen to transfer to the inspection program. The licensing bases are the same in both cases and the issue, therefore, is a level of confidence in compliance or safety and whether that is accomplished through NRR review or the inspection program. The use of both the licensing and inspection programs can offer advantages in terms of efficiencies and staff understanding of the actual plant design and operation. Using combined NRC processes does, however, require additional coordination between NRR, regional offices and licensees.

2 Obligations

Obligations or regulatory requirements involve those conditions or actions that are legally binding requirements imposed on licensees through applicable rules, regulations, orders, and licenses (including technical specifications and license conditions). The imposition of obligations or regulatory requirements during routine interactions with licensees should be reserved for matters that satisfy the criteria of 10 CFR 50.36, "Technical specifications," or are otherwise found to be of high safety or regulatory significance. In such matters concerning the adequate protection of the public health and safety, changes to obligations cannot generally be made by licensees without prior NRC approval.

The highest tier of obligations could be considered to be laws such as the Atomic Energy Act (AEA) and National Environmental Policy Act. The NRC implements these laws through its regulations in Title 10 of the Code of Federal Regulations. The authorizing legislation, Administrative Procedures Act (APA), and other legislation will not be discussed in this version of the office instruction because the actual legislation is not a common reference in the processes associated with the control of licensing bases information. A future revision of this office instruction might include additional discussions of the legislation that forms the bases of NRC requirements and processes, if the need for such information is identified by the staff or other stakeholders.

2.1 Regulations

This section defines the control of those parts of the licensing bases established by regulations. Examples include the requirements to have the capability to cope with a station blackout, to install and maintain equipment to respond to an anticipated transient without scram, and to evaluate the performance of the emergency core cooling system.[2] Some regulations have processes for change-control, reporting and other characteristics defined within the regulation. The most obvious example of this is the programs defined by 10 CFR 50.55a for inservice inspection and inservice testing of systems, structures, and components that are within the scope of NRC accepted industry codes and standards. Since important characteristics for managing the licensing bases associated with different regulations will vary, this section outlines the processes as follows:

1. General Regulations (those without defined processes within the specific regulation)

2. 10 CFR 50.55a, Codes and standards

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[2] Note that regulations such as 10 CFR 50.59 and 10 CFR 50.54 are obligations in that licensees are required to conform to the regulations. The regulations require general programmatic controls and are therefore discussed in more detail in Section 3, "Mandated Licensing Bases Documents." Some discussions within Section 2, "Obligations," remain applicable to regulations defining the characteristics of the mandated licensing bases documents. Many licensees have, for example, requested an exemption in accordance with 10 CFR 50.12 from a requirement contained in 10 CFR 50.71 that defines a specific time constraint for submitting updates to final safety analysis reports.

3. 10 CFR 50.46, Acceptance criteria for emergency core cooling systems for light-water nuclear power plants

4. 10 CFR 50.80, Transfer of licenses

5. Other Rules of Special Interest
   - 10 CFR 50.9, Completeness and accuracy of information
   - 10 CFR 50.65, Requirements for monitoring the effectiveness of maintenance at nuclear power plants
   - 10 CFR 50.54(x)
   - 10 CFR 50.109, Backfitting
   - Appendix A, General design criteria for nuclear power plants
   - Appendix B, Quality assurance criteria for nuclear power plants

As mentioned previously, the rules that define the control of mandated licensing bases documents (e.g.,10 CFR 50.54 and 50.59) are themselves obligations in that licensees must comply with the requirements defined within the rules. These rules will be discussed in more detail in Section 3 on mandated licensing bases documents.

Some other rules contain a specific reporting requirement or other nuances regarding the licensing bases for a specific issue (e.g., 10 CFR 50.61 – includes a reporting requirement for RT_{PTS}) but are not discussed in detail in this version of the office instruction. See the appropriate subject matter experts if you have questions about these regulations. We may add information about these regulations in a revision of this office instruction if such additions are supported by feedback from the staff and other stakeholders.

The following discussions and tables include discussions about the characteristics for general regulations as well as the major regulations with specific controls included within the regulation.

2.1.1 General Regulations

2.1.1 - General Regulations	
Characteristic	**Discussion**
Regulatory Bases	Technical and administrative requirements defined in various regulations
Location of Licensing Bases Information	The component of the licensing bases for regulations consists of the regulations themselves. Supporting information regarding the meaning of regulations may be found in the Statements of Consideration, Proposed Rulemaking, and the notice associated with the Final Rulemaking. Details regarding the way a specific licensee has chosen to comply with a regulation are often found in the technical specifications, updated FSAR , commitments in docketed correspondence, or other documents (within or sometimes outside of the licensing bases). When the

	licensee is provided flexibility in choosing how to comply with a regulation, the associated licensing bases are usually controlled through the other elements (license, updated FSAR, etc.). NRC regulatory guides and other documents may provide additional information about the history and details of a regulation. Regulatory guides provide an acceptable approach (but not the only approach) for a licensee to satisfy a regulation. Regulatory guides are discussed in Section 6.
Nonconformances and/or Unplanned Changes	Discovered noncompliances or temporary deviations from regulations that define requirements on specific SSCs are usually handled in accordance with a licensee's corrective action program. Plant operation is actually governed by associated technical specifications and evaluations regarding the safety significance of the problem. The licensing bases are usually not affected and the noncompliance is addressed within the licensee's corrective action program and the NRC's enforcement and oversight programs. Generic Letter 91-18 provides guidance on addressing degraded and nonconforming conditions. Discovered noncompliances or other temporary deviations from regulations that do not define requirements on specific SSCs or operating practices governed by license conditions or technical specifications are handled within the licensee's corrective action program and the NRC's enforcement and oversight programs. The licensing bases are usually not affected by such conditions.
Planned or Routine Change Control	A licensee may apply, in accordance with 10 CFR 50.12, to the NRC for an exemption from the requirements defined in a regulation* If the staff determines that issuance of an exemption to a licensee (or multiple licensees) without receipt of a written request is more effective in meeting our performance goals, the staff may issue the exemption on its own initiative (in accordance with 10 CFR 50.12). Note that issuance of exemption requires publication of an environmental assessment. * Note – a licensee could petition to change the rule. This option is not a routine way to revise the licensing bases for a specific plant and is not discussed in this office instruction.
Reporting of Changes to the NRC	There is no specific requirement for reporting a noncompliance with most regulations. Some may be reportable in accordance with 10 CFR 50.72 and 50.73. In general, temporary noncompliances or deviations are handled under the inspection and enforcement programs.

	Regarding planned or long-term deviations from a regulation, exemption requests require NRC approval and involve a specific request from a licensee.
NRC Verification or Monitoring	Ensuring that licensees comply with regulations and other obligations is normally performed as part of the NRC inspection program. See the NRC Inspection Manual for additional information. A licensee's compliance with some regulations may receive a detailed review only during the licensing process and subsequent changes to the licensing bases. Such verifications usually involve design features or supporting analyses that involve specialized review processes (e.g., reactor vessel RT_{PTS}).
Enforcement Practices	Noncompliance with a regulation is evaluated in accordance with the NRC's inspection and enforcement programs. The appropriate response, from non-cited violation through escalated enforcement action, considers several factors, including the safety significance of the violation. See NRC Enforcement Manual.
Public Participation	The public is provided an opportunity to participate, by providing comments, during the development of a regulation. The process for NRC review of a licensee's request for an exemption from a regulation uses correspondence that is available for public review. No specific opportunity to comment or to request an adjudicatory proceeding are provided for licensee-specific reviews. An environmental assessment and finding of no significant impact is published in the Federal Register shortly before the issuance of an exemption.
NRC Staff Guidance	

2.1.2 10 CFR 50.55a, Codes and Standards

2.1.2 - 10 CFR 50.55a	
Characteristic	**Discussion**
Regulatory Basis	10 CFR 50.55a, Codes and standards, incorporates portions of industry codes and standards, such as the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, into the regulations. The regulation defines the applicable addenda and editions as well as additional NRC requirements and related NRC processes, such as updating and change-control.
Location of Licensing Bases Information	Much of the information associated with a licensee's implementation of the testing and surveillance requirements in 10 CFR 50.55a is contained in their Inservice Inspection (ISI) program documentation and

	the Inservice Testing (IST) program documentation. These programs are submitted to the NRC at specified intervals. Information related to the design and construction requirements contained in 10 CFR 50.55a(c), "Reactor coolant pressure boundary," may be found in plants' updated FSARs.
Nonconformances and Unplanned Changes	Discovered noncompliances or temporary deviations from regulations that define requirements on specific SSCs are usually handled in accordance with a licensee's corrective action program. A complication related to 10 CFR 50.55a is that some plants' technical specifications include meeting the rule as a limiting condition for operation. This may preclude continued plant operation with a nonconformance unless the NRC provides its approval. Although the guidance in Generic Letter 91-18 may provide useful guidance for evaluating the nonconforming or degraded condition, other actions (e.g., granting a relief or authorizing an alternative to the Code) may be required. The change-control processes (described below) included in 10 CFR 50.55a include the NRC authorizing proposed alternatives to the ASME code requirements (see 10 CFR 50.55a(3)). The NRC occasionally evaluates a change to the licensing bases for 10 CFR 50.55a and verbally approves a proposed alternative to the Code. The use of verbal authorizations should be limited to those circumstances in which a written request and written authorization results in an unwarranted adverse impact (such as preventing a plant startup). Verbal authorizations should be followed with a written request and written approval in order to maintain the licensing bases information and to ensure transparency of NRC processes. The NRC staff may also issue an interim relief which, although performed using official NRC records, uses an abbreviated process in order to quickly issue the relief (interim reliefs cover short periods of time or cover the interval between the issuance of the interim relief and the issuance of the permanent change). OGC does not concur in interim reliefs. Approval authority for verbal or interim reliefs is the same as described for routine relief requests in the NRR procedure for Signature Authority.
Planned or Routine Change Control	Licensees can propose an alternative to the code requirements in accordance with 10 CFR 50.55a(a)(3) ((i) proposed alternatives provide acceptable level of quality and safety or (ii) code requirement results in hardship or unusual difficulty without a compensatory increase in level of safety or quality) or request relief in accordance with 10 CFR 50.55a(f)(5) for IST or 10 CFR 50.55a(g)(5) for ISI (for code requirements that are impractical). Relief from reactor vessel shell weld examinations are requested in accordance with 10 CFR 50.55a(g)(6)(ii).

	Relief requests [the term relief request is usually used for either proposed alternatives (50.55a(a)(3)) or cases of impracticality (50.55a(f) or (g))] are submitted by licensees and are reviewed by the NRC staff. The approval or denial of the requested relief(s) is documented in a letter (with enclosed evaluation) to the licensee. The staff should make sure that the intended duration of the granted relief (e.g., a specific 10-year interval or the remainder of the plant license) is clearly defined. Note that the requirements of 10 CFR 50.55a and the ASME Code define requirements for 10-year intervals and defined periods within the intervals. Some reliefs (primarily in ISI) are based on as-performed testing. This results in some reliefs being confirmatory instead of being prior approvals. 10 CFR 50.55a(f)(5) and 50.55a(g)(5) require licensees to submit requests for reliefs from IST and ISI requirements that are determined to be impractical not later than 12 months after the expiration of the 120-month interval in which the test is determined to be impractical. The term commitment is sometimes used to describe a proposed alternative to a Code requirement. Although regulatory commitments (see Section 4) can be made as part of a relief request, the proposed alternatives submitted as part of the licensee's request for relief generally become part of the licensee's ISI or IST programs and are therefore obligations (i.e., changing from one alternative to another alternative would require NRC approval).
Reporting of Changes to the NRC	Licensees are required to submit revised ISI and IST programs every 10 years. Reports on the results of testing may be required by the rules or other obligations (e.g., steam generator tube inspection reports are included in technical specifications). Requests for deviations from the requirements of 10 CFR 50.55a are submitted to the NRC. A nonconformance or degraded condition may also be reportable under 10 CFR 50.72 or 73.
NRC Verification or Monitoring	Ensuring that licensees comply with regulations and other obligations is normally performed as part of the NRC inspection program. See the NRC Inspection Manual for additional information.
Enforcement Practices	Noncompliance with a regulation is evaluated in accordance with the NRC's inspection and enforcement programs. The appropriate response, from non-cited violation through escalated enforcement action, considers several factors, including the safety significance of the violation. See NRC Enforcement Manual.
Public Participation	The process for NRC review of programs and reliefs under 10 CFR 50.55a are generally performed with correspondence available for public review. No specific opportunity to comment or to request an adjudicatory proceeding are provided for licensee-specific reviews.

NRC Staff Guidance	NRR Office Letter 808, "Relief Request Reviews " (To become Office Instruction LIC-102) GL 90-05, "Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 Piping" NUREG-1482: "Guidelines for Inservice Testing at Nuclear Power Plants" NUREG/CR-6396: "Examples, Clarifications, and Guidance on Preparing Requests for Relief from Pump and Valve Inservice Testing Requirements (INEL-95/0512)"

2.1.3 Acceptance criteria for emergency core cooling systems for light-water nuclear power plants

2.1.3 - 10 CFR 50.46	
Characteristic	**Discussion**
Regulatory Basis	The familiar acceptance criteria (2200°F peak clad temperature, coolable geometry, etc.) for emergency core cooling systems are provided in 10 CFR 50.46. Most of the rule and related information in Appendix K address the evaluation models (computer codes, correlations, etc.) that are used to model the performance of the ECCS and demonstrate compliance with the rule.
Location of Licensing Bases Information	Most of the licensing bases information showing compliance with 10 CFR 50.46 is located in topical reports submitted by licensees or fuel vendors that describe the evaluation models. Plant specific information regarding assumptions and use of the evaluation models are usually contained in the technical specifications and updated FSAR . The translation of the evaluation model assumptions into plant specific technical specifications, surveillance tests, or other performance measure for specific SSCs is addressed by other requirements. For example, translation of an ECCS evaluation model assumption to a plant-specific design or surveillance requirement would, if not addressed by technical specifications or other licensing bases element, probably be covered by Appendix B.
Nonconformances and/or Unplanned Changes	Errors discovered in an ECCS evaluation model are addressed by licensee and vendor corrective action programs. If the error affects another element of the licensing bases, a technical specification limit for

	example, corrective actions may include limitations on reactor operations and subsequent revision to another licensing bases document. If the error is significant (> 50°F increase in calculated peak clad temperature), the licensee must provide a plan within 30 days that includes a schedule for providing reanalysis or taking other action as may be needed to show compliance with 10 CFR 50.46 requirements.
Planned or Routine Change Control	Planned improvements or other changes to an evaluation model are submitted by the licensee or vendor for review by NRR. Changes to the evaluation model may accompany or precede changes to other elements of the licensing bases (technical specifications, updated FSAR).
Reporting of Changes to the NRC	New or revised evaluation models are submitted for review prior to application to a specific facility. Changes to or errors discovered in evaluation models are reported to the NRC in an annual report. Changes or errors are considered significant when they (individually or cumulatively) exceed 50°F and must then be reported within 30 days. See 10 CFR 50.46(a)(3) for additional details. Any change or error correction that results in a calculated peak clad temperature in excess of 2200°F is also reportable in accordance with 10 CFR 50.72/50.73
NRC Verification or Monitoring	The verification of compliance with 10CFR 50.46 is primarily via reviews performed by NRR. Actual performance of ECCS, including consistency with evaluation model assumptions, is accomplished through related licensing bases reviews (e.g., technical specifications) and through the NRC inspection program.
Enforcement Practices	Noncompliance with 10 CFR50.46 is evaluated in accordance with the NRC's enforcement programs. The appropriate response, from non-cited violation through escalated enforcement action, considers several factors, including the safety significance of the violation. See NRC Enforcement Manual.
Public Participation	The process for NRC review of evaluation models is generally performed with correspondence available for public review. No specific opportunity to comment or to request an adjudicatory proceeding are provided for specific reviews.

	The subsequent application of a revised evaluation model may include changes to technical specifications which do include an opportunity to comment or request a hearing by affected members of the public.
NRC Staff Guidance	

2.1.4 License Transfers

With the advent of increased competition in the electric power industry, the NRC has received an increasing number of requests to transfer power reactor operating licenses. The NRC has received requests for different types of transfers because of the different corporate strategies of its licensees or different State approaches to deregulation. Some licensees are choosing or are being required by their states to get out of the electricity generating business entirely, or have determined that they cannot run particular nuclear units economically. Thus, plants are being sold to those companies that have decided to focus on electricity generation. Other licensees may decide that they are too small to compete effectively in a market environment and seek merger partners. Still other licensees form parent holding companies that will allow them to diversify into other areas or markets. Finally, some companies form nuclear operating company subsidiaries or alliances to increase technical focus or take advantage of economies of scale that can result when an operating company runs several nuclear plants. Some electric utilities and/or electric generating companies have indicated their intent to buy several nuclear plants and obtain economies of scale through engineering services consolidation, outage management, and other areas where increased efficiencies can be achieved without compromising safety.

The provisions of Section 184 of the Atomic Energy Act of 1954, as amended (AEA), and the NRC's regulations at 10 CFR 50.80, stipulate that no transfer can occur unless the NRC gives its consent in writing. These provisions apply to both direct and indirect transfers. Direct transfers are generally those that involve transfer of ownership or operating authority of the plant itself from one entity to another -- for example, the sale of a plant. Indirect transfers are generally associated with transfers of ownership involving the licensee rather than the specific facility -- for example, the formation of a new parent holding company above a licensee.

2.1.4 – License Transfers	
Characteristic	**Discussion**
Regulatory Basis	NRC approval of license transfers is required by 10 CFR 50.80. Specific areas to consider as part of a request to transfer a license are contained in 10 CFR 50.40, 50.33, and 50.75. License transfers are approved using the vehicle of an order in accordance with 10 CFR 2.202. License transfers often require an amendment to the facility operating license in accordance with 10 CFR 50.90.

Location of Licensing Bases Information	Information regarding the holder of an operating license is found in the license, within the updated FSAR, and within reports and submittals required by specific regulations or other regulatory requirements (e.g., company annual reports, decommissioning funding reports, etc.)
Planned or Routine Change Control	NRC approval of license transfers is required by 10CFR 50.80. Specific areas to consider as part of a request to transfer a license are contained in 10 CFR 50.40, 50.33, and 50.75. License transfers are approved using the vehicle of an order in accordance with 10 CFR 2.202. License transfers often require an amendment to the facility operating license in accordance with 10 CFR 50.90.
Reporting of Changes to the NRC	License transfers are reported in the form of requests for approval.
Public Participation	The transfer of an operating license uses processes such as license amendments and issuance of orders. See the specific licensing bases element for the opportunities for public participation associated with a revision to or use of that element. The NRC also publishes in the Federal Register a notice of receipt of an application for approval of a license transfer involving Part 50 and Part 52 licenses. Any person whose interest may be affected by the NRC's action on the application may request a hearing or petition for leave to intervene within 20 days of the FR notice.
NRC Staff Guidance	(1) Financial Qualifications and Decommissioning Funding Assurance -- a final SRP was issued in February 1999 as NUREG-1577, Rev. 1. (2) Antitrust -- a final SRP was issued in December 1997 as NUREG-1574. In its decision on the Wolf Creek license transfer preceding (CLI-99-19; 49 NRC 441 (1999)), the Commission determined that the Atomic Energy Act does not require or authorize antitrust reviews of post-operating license transfer applications. Therefore, the staff no longer conducts antitrust reviews for license transfer applications. (3) Standard Review Plan on Foreign Ownership, Control, or Domination -- See RIS 2000-01 dated February 1, 2000. (4) Non-owner operators -- a draft regulatory guide was issued for public comment in December 1999. Per a Commission SRM dated October 24, 2000, the staff issued RIS 2001-01 in lieu of the regulatory guide. The guidance addresses the degree to which a licensee transfers operating authority to another entity (e.g., a contractor). Whether a transfer requires approval depends on the extent to which decision-making authority is being transferred.

	(5)Technical Qualifications -- an SRP was issued in November 1999. (6) Integrated SRP on All Aspects of License Transfers -- the SRP was approved in December 1999. It incorporates elements from other SRPs relevant to license transfers.

2.1.5 Other Rules of Special Interest

In addition to the previously mentioned regulations that deal directly with the control of licensing bases information, there are other rules that are cited or for which questions arise regarding the control of licensing bases information.

2.1.5.1 10 CFR 50.9, "Completeness and accuracy of information"

Licensees are required to provide the NRC with information that is "complete and accurate in all material respects." The regulation also requires licensees to notify the NRC of information that has a "significant implication for public health and safety or common defense and security." Although the rule could be read to be a control on licensing bases information, it has rarely been referenced in such matters. As a general practice, the staff should not rely on 10 CFR 50.9 for providing a change-control or reporting mechanism for licensing bases information. Although it might be applicable, the use of the rule is somewhat subjective given it requires an assessment as to the materiality and significance of the information and as such, is not a reliable mechanism for the control of licensing bases information. It is better that the staff consider 10 CFR 50.9 as a general rule regarding the overall relationship between the NRC and its licensees and not consider it as a process for the control of licensing bases information.

2.1.5.2 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants"

The maintenance rule requires that each licensee monitor the performance or condition of within-scope SSCs against licensee-established goals to ensure they are capable of fulfilling their intended function. Within the scope of the rule are (1) safety-related SSCs relied upon during design bases events (see 10 CFR 50.34(a) and 10 CFR 100.11), (2) non-safety related SSCs (i) that are relied upon to mitigate accidents or transients or are used in plant emergency operating procedures, (ii) whose failure could prevent safety-related SSCs from fulfilling their function, and (iii) whose failure could cause a reactor scram or actuation of a safety-related system. Licensees are required to assess the performance of equipment and maintenance activities to meet the objective of preventing failures of SSCs while minimizing the unavailability of SSCs for monitoring and maintenance. A recent change to the rule, 10 CFR 50.65(a)(4), requires licensees to assess the safety significance of planned maintenance activities. In this regard the rule is an additional consideration, beyond the technical specifications and other parts of the licensing bases, for the control of plant configurations during maintenance activities. The maintenance rule itself is within the set of obligations that form part of the licensing bases. As a performance based rule, 10 CFR 50.65 requires licensees to consider risk and to compare maintenance activities and failures due to ineffective maintenance against licensee defined performance goals. The specific assessments of plant configurations or the specific performance goals for the SSCs under the maintenance rule are not generally considered to be themselves part of the licensing bases. They are, instead, ancillary information that may be reviewed as part of the NRC inspection and assessment program to determine if the licensee is complying with the maintenance rule or to determine if the maintenance rule is providing the desired level of safety performance. See Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," and other maintenance rule guidance documents for additional information.

2.1.5.3 10 CFR 50.54(x) and (y)

The statements in 10 CFR 50.54(x) and (y) were included in our regulations to ensure that the need to maintain compliance with the license would not preclude plant operators from making appropriate safety decisions. The rules state that a senior licensed operator may approve a reasonable action that departs from a license condition or technical specification in an emergency when such action is immediately needed to protect the public health and safety and no action consistent with the license conditions or technical specifications that can provide equivalent protection is immediately apparent. Reporting requirements regarding the use of this provision are contained in 10 CFR 50.72.

2.1.5.4 10 CFR 50.72, "Immediate notification requirements for operating nuclear power reactors," and 50.73, "Licensee event report system"

Reporting requirements specified in 10 CFR 50.72 and 50.73 are intended to support NRC functions such as (1) responding to emergencies or incidents, (2) assessing conditions to determine if safety issues require an NRC response (either for a specific licensee or for multiple plants), and (3) maintaining a sufficient awareness of events or conditions to support various regulatory functions and expectations. The reporting requirements occasionally involve reports of a failure to comply with a facility's licensing bases. The reporting requirements involving such issues were intended to serve the above goals and do not replace the normal means of controlling, reporting and NRC verification of the licensing bases. The reporting requirements were recently revised and removed the criterion: "a condition that is outside the design bases of the plant" which has been an issue regarding the interface between the control of licensing bases information and 10 CFR 50.72/50.73.

2.1.5.5 10 CFR 50.109, Backfitting

Backfitting is the modification or addition of a requirement resulting from a new or amended provision in NRC rules or the imposition of a regulatory staff position that is either new or different from a previously applicable staff position. With the exception of actions required to restore compliance with the licensing bases or to provide adequate protection of public health and safety, the backfit rule requires the NRC staff to perform a systematic and documented analysis to justify the new or revised requirements. Additional information regarding the staff's responsibility to avoid unintended backfits and the process to impose justified backfits is provided in NRR Office Letter 901 (to become Office Instruction LIC-202).

2.1.5.6 Appendix A, "General Design Criteria"

Pursuant to the provisions of 10 CFR 50.34, "Contents of applications; technical information," an applicant for a construction permit must include the principal design criteria for a proposed facility. The General Design Criteria (GDC) establish minimum requirements for the principal design criteria for water-cooled nuclear power plants. For the most part, a plant's compliance with the GDC was verified during the original licensing process. Although the GDC may be viewed as legally binding on licensees (in the absence of an approved alternative design bases), issues associated with licensing, inspection or enforcement are usually tied to more explicit NRC requirements (technical specifications or specific regulations).

The General Design Critieria are not applicable to plants with construction permits issued prior to May 21, 1971. At the time of the promulgation of Appendix A, the Commission stressed that the GDC were not new requirements and were promulgated to more clearly articulate the licensing requirements and practice in effect at that time. While compliance with the intent of the GDC is important, each plant licensed before the GDC were formally adopted was evaluated on a plant specific bases, determined to be safe, and licensed by the Commission. Furthermore, current regulatory processes are sufficient to ensure that plants continue to be safe and comply with the intent of the GDC.

2.1.5.7 Appendix B, "Quality assurance criteria for nuclear power plants"

A discussion of licensee-specific quality assurance programs used to implement the requirements of Appendix B is included in Section 3, Mandated Licensing Bases Documents. The requirements of Appendix B are included here to stress the importance of the provisions in the appendix in binding together and filling gaps in regulations governing safety-related SSCs. Appendix B consists of 18 criteria and provides requirements related to quality assurance programs, procurement, design, document control, testing, audits, and corrective actions. Additional information on Appendix B and its implementation can be found in licensee quality assurance programs, referenced industry codes and standards, and NRC regulatory guides.

2.2 Operating License & Technical Specifications

Licenses have been issued under two separate sections of the Atomic Energy Act of 1954, as amended (AEA): a commercial license under Section 103 and a research and development license under Section 104b. Prior to the 1970 amendments to the AEA, a Section 103 license required a finding of "practical value." The Atomic Energy Commission (AEC) would have based a finding of "practical value" for a type of reactor on a reliable estimate of its economics, based upon a demonstration of the technology and plant performance. In addition, after an AEC finding of "practical value" for a particular type of reactor, licenses issued under Section 103 were subject to a prelicensing review to determine if the proposed license would tend to create or maintain a situation inconsistent with antitrust laws. At that time, the AEC did not believe that it had sufficient information to make the "practical value" finding and all licenses were issued under Section 104b. In 1970, the AEA was amended to abolish the requirement of a finding of practical value and stated that any license issued for a utilization or a production facility for industrial or commercial purposes must be issued under Section 103. Note, however, that the operating license for a facility whose construction permit had previously been issued under Section 104b would likewise be issued under Section 104b, as stated in Section 102b of the AEA. The AEA does not specifically identify a license term for Section 104b licenses, although the AEA does restrict Section 103 licenses to 40 years. 10 CFR 50.51, "Continuation of license," limits reactor licenses to 40 years and does not distinguish between licenses issued under Sections 103 and 104b.

The Commission's practice with respect to issuance of operating licenses has varied. At one time, the staff issued provisional operating licenses (under Section 104b), followed by a full-term operating license. In addition, the staff, in some cases, issued a low power operating license (LPOL) which was amended to allow full-power operation. The most recent practice was to issue an LPOL followed by a separate FPOL. Operating licenses include a list of conditions. The conditions usually include the authorized power level of the reactor, the incorporation of technical specifications (as Appendix A), requirements to maintain fire protection and security plans, and license-specific conditions regarding post-TMI issues.

2.2.1 Operating License (including license conditions)

A typical operating license contains various conditions, including those related to security plans, fire protection programs, and license-specific technical or programmatic requirements. A requirement for reporting violations of the license conditions was added as a license condition for more recent licensees. The inclusion of specific technical or programmatic requirements in the license means that the license conditions occasionally need to be revised.

2.2.1 - Operating License (including license conditions)	
Characteristic	**Discussion**
Regulatory Basis	Part 2 to 10 CFR has various rules that define the licensing process. There are generally related rules in Part 50 and these include 10 CFR 50.57, "Issuance of operating licenses," and 10 CFR 50.58, "Hearings and report of the Advisory Committee on Reactor Safeguards." 10 CFR 50.54, "Conditions of licenses," imposes various requirements on licensees ("...deemed conditions in every license issued:") but the conditions have the attributes of regulations (See previous section) The change control regulations are 10 CFR 50.90, "Application for amendment of license or construction permit," 10 CFR 50.91, "Notice for public comment; State consultation," and 10 CFR 50.92, "Issuance of amendment."
Location of Licensing Bases Information	The requirements are included in the license, including incorporated conditions.
Nonconformances and/or Unplanned Changes	Unless the deviation results in entry into a technical specification action statement, unplanned deviations from operating licenses are handled similar to regulations and orders.

	Discovered noncompliances or temporary deviations from license conditions that define requirements on specific SSCs are usually handled in accordance with a licensee's corrective action program. Plant operation is actually governed by any associated technical specifications and evaluations regarding the safety significance of the problem. The licensing bases are usually not affected and the noncompliance is addressed within the licensee's correction action program and the NRC's enforcement and oversight programs. Generic Letter 91-18 provides guidance on addressing degraded and nonconforming conditions. Discovered noncompliances or other temporary deviations from license conditions that do not define requirements on specific SSCs or operating practices governed by license conditions or technical specifications are handled within the licensee's correction action program and the NRC's enforcement and oversight programs. The licensing bases are usually not affected by such conditions.
Planned or Routine Change Control	The processes for the planned or routine revision of a license is the license amendment process (in accordance with 10 CFR 50.90, NRR Office Letter 803 (Office Instruction LIC-101), and other requirements and guidance documents).
Reporting of Changes to the NRC	Some recent licenses include a reporting requirement for deviations from license conditions. Other reporting requirements, such as 10 CFR 50.72 and 50.73, may also require a report on a particular issue that also involves deviation from a license condition. Prior NRC approval is required for planned changes to the license.
NRC Verification or Monitoring	Ensuring that licensees comply with the license and other obligations is normally performed as part of the NRC inspection program. See the NRC Inspection Manual for additional information.
Enforcement Practices	Noncompliance with a license, including conditions, is evaluated in accordance with the NRC's inspection and enforcement programs. The appropriate response, from non-cited violation through escalated enforcement action, considers several factors, including the safety significance of the violation. See NRC Enforcement Manual.
Public Participation	The applications for a revision to the license, the staff's issuance or denial of the revision, as well as any information important to the staff's decision-making process are available for public review. In addition, the public is provided with an opportunity to request a hearing (see 10 CFR 50.58 and 10 CFR 2.1201-1263). As described in 10CFR50.91, the staff will issue a notice of a proposed license change with a determination regarding whether the proposed change involves a significant hazards consideration (see 10 CFR 50.92). If the NRC staff proposes that the change involves no significant hazards considerations, the NRC will issue a notice (see 10 CFR 50.91) that

	announces the opportunity for a hearing and solicits public comment on the proposed no significant hazards consideration determination. In such cases, an amendment may be issued even if a hearing is requested, provided that the NRC issues a final no significant hazards consideration determination. In the case where the staff does not make a determination that the proposed change involves no significant hazard, a notice will be issued that provides for a hearing prior to the issuance of the requested amendment. See 10 CFR Part 2 for details regarding the hearing process.
NRC Staff Guidance	NRR Office Letter 803 (Office Instruction LIC-101)

2.2.2 Technical Specifications

Section 182a of the Atomic Energy Act (the Act) requires applicants for nuclear power plant operating licenses to include technical specifications (TSs) as part of the license. In 10 CFR 50.36, the Commission established the regulatory requirements related to the content of TSs. That regulation requires that the TSs include items in five specific categories, including (1) safety limits, limiting safety system settings, and limiting control settings; (2) limiting conditions for operation; (3) surveillance requirements; (4) design features; and (5) administrative controls. However, the regulation does not specify the particular requirements to be included in TSs.

Within the broad outline included in the rule, the format of TSs have evolved over the years. In the mid-1970's, the NRC developed and issued NUREGs that provided a standard for format and content (standard technical specifications or STS). Plants licensed after that time adopted the STS. Some plants that were licensed prior to that time converted their "custom TS" to the STS format and others retained their original TS structure. In the mid-1980's, the NRC undertook a TS improvement program to improve the format and content of TS. This effort included some incremental changes to the recommended content of the STS (issued as "line item improvements" using generic letters) and ultimately led to the issuance of a revised set of NUREGs with standard TS (often called the improved STS or iSTS). Many licensees have or are planning to convert to the iSTS. The iSTS are being revised on an ongoing basis to incorporate lessons learned from industry and staff, incorporate desired changes, and incorporate risk insights.

The NRC developed criteria, as described in the "Final Policy Statement on Technical Specifications Improvements for Nuclear Power Reactors" (58 FR 39132), to determine which of the design conditions and associated surveillances should be located in the TSs as limiting conditions for operation. These criteria formed the bases for the content in the iSTS. Four criteria were subsequently incorporated into the regulations by an amendment to 10 CFR 50.36 (60 FR 36953):

1. installed instrumentation that is used to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary;

2. a process variable, design feature, or operating restriction that is an initial condition of a Design Bases Accident or Transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier;

3. a structure, system, or component that is part of the primary success path and which functions or actuates to mitigate a Design Bases Accident or Transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier;

4. a structure, system, or component which operating experience or probabilistic safety assessment has shown to be significant to public health and safety.

2.2.2 - Technical Specifications	
Characteristic	**Discussion**
Regulatory Basis	As described above, the required content of technical specifications is provided in 10 CFR 50.36. The rule defines the basic format of technical specifications (to include safety limits and limiting safety system settings, limiting conditions for operation, surveillance requirements, design features and administrative controls). The rule defines four criteria to determine if a limiting condition for operation is required for specific equipment. The rules associated with amending technical specification are 10 CFR 50.90, 50.91, 50.92.
Location of Licensing Bases Information	The technical specifications are an appendix to the operating license. Important background information (although not necessarily licensing bases information) regarding technical specifications can be found in licensee's applications and NRC safety evaluations. Bases to the technical specifications provide additional details and insights into the intent of the specifications but are not actually part of the technical specifications. The Bases are discussed in more detail in the mandated licensing bases documents section.
Nonconformances and/or Unplanned Changes	Technical specifications require a licensee to take remedial actions in those cases in which a technical specification requirement can not be met. These are generally referred to as actions and the technical specifications may require that the action be taken within a specified time. When a licensee is unable to fulfil the technical specification requirements, including taking action within the specified time, a provision within the technical specifications requires the licensee to shut down the plant. The NRC developed a tool for addressing urgent cases where a noncompliance with technical specifications required a plant to shut down even though the noncompliance did not translate into a safety concern. This tool is the notice of enforcement discretion (NOED).

	NOEDs are discussed in Part 9900 of the NRC inspection manual and in NRC enforcement policy. The issuance of an NOED is not a revision of the licensing bases for a facility. It is, instead, an acknowledgment of the noncompliance with the technical specifications and a notice from the NRC to the licensee that enforcement action will not be taken (does not preclude enforcement action for the conditions that led to the need for the NOED). NOEDs issued by NRR are usually followed by a license amendment to formally change the licensing bases. Licensees may request technical specification changes using the emergency or exigent provisions in 10 CFR 50.91. The emergency provision allows the NRC to immediately issue technical specification changes without prior public notice provided the criteria in 10 CFR 50.91(a)(5) are satisfied (including a finding that the request involves no significant hazards consideration). The exigent amendment process (10 CFR 50.91(a)(6)) involves an abbreviated public notice period in the Federal Register or the use an alternative to the Federal Register. The technical review and other aspects of these amendments are the same as those discussed below for planned changes. NRC Administrative Letter 98-10, "Dispositioning of Technical Specifications that are insufficient to assure plant safety," provided guidance on how to address "non-conservative" TSs.
Planned or routine change-control	The processes for the planned or routine revision of a license is the license amendment process (in accordance with 10 CFR 50.90, NRR Office Letter 803 (Office Instruction LIC-101), and other requirements and guidance documents).
Reporting of Changes to the NRC	Some reports to the NRC may address violations of technical specifications. Shutdown of a plant in accordance with some TS requirements is reportable under 10 CFR 50.72. A special report is required by 10 CFR 50.36 if a safety limit is violated. Prior NRC approval is required for planned changes to the license. Unplanned changes or continued operation in noncompliance with TS requirements require NRC involvement in the form of an emergency/exigent license amendment or an NOED
NRC Verification or Monitoring	Ensuring that licensees comply with technical specifications and other obligations is normally performed as part of the NRC inspection program. See the NRC Inspection Manual for additional information.
Enforcement Practices	Noncompliance with a TS requirement is evaluated in accordance with the NRC's inspection and enforcement programs. The appropriate response, from non-cited violation through escalated enforcement action, considers several factors, including the safety significance of the violation. See the NRC Enforcement Manual.

Public Participation	The applications for a revision to the license, the staff's issuance or denial of the revision, as well as any information important to the staff's decision-making process are available for public review. In addition, the public is provided with an opportunity to request a hearing (see 10 CFR 50.58 and 10 CFR 2.1201-1263). As described in 10 CFR 50.91, the staff will issue a notice of a proposed license change with a determination regarding whether the proposed change *involves a significant hazards consideration* (see 10 CFR 50.92). If the NRC staff proposes that the change involves no significant hazards considerations, the NRC will issue a notice (see 10 CFR 50.91) that announces the opportunity for a hearing and solicits public comment on the proposed no significant hazards consideration determination. In such cases, an amendment may be issued even if a hearing is requested, provided that the staff prepares a final no significant hazards consideration determination and notifies the Commission. In the case where the staff does not make a determination that the proposed change involves no significant hazard, a notice will be issued that provides for a hearing prior to the issuance of the requested amendment. See 10 CFR Part 2 for details regarding the hearing process. See above for handling emergency and exigent amendment applications.
NRC Staff Guidance	NRR Office Letter 803 (Office Instruction LIC-101)

2.3 Orders

An order is a written NRC directive used to modify, suspend, or revoke a license (including the technical specifications); impose civil monetary penalties; or take other action as may be proper. Orders also may be issued in lieu of, or in addition to, civil penalties for Severity Level I, II, or III violations. This office instruction will focus on those orders used to modify the licensing bases of a nuclear power facility (License Modification Orders). Licensees typically have 20 days to provide a written response to an order. An order may be used to confirm an action committed to by a licensee. This type of order is called a confirmatory order. In the case of a confirmatory order, the licensee waives its right to a hearing. Other parties potentially affected by the order maintain their right to request a hearing. Additional information regarding the issuance of orders is provided in the NRC Enforcement Manual.

The largest contribution that orders have had to the licensing bases of nuclear power reactors involves the orders issued in the aftermath of the accident at Three Mile Island. There were generally two rounds of orders associated with plant modifications and revising plants' TS to implement the technical and programmatic changes described in NUREG 0737, "Clarification of 8TMI Action Plan Requirements." The confirmatory orders issued to implement NUREG-0737 generally reference licensee submittals that included detailed descriptions of modifications and related schedules. The level of detail covered by the TMI orders is comparable to the levels specified in NUREG-0737 for the various technical or programmatic requirements (i.e., The licensees' submittals included both licensing bases information that was confirmed by the orders and ancillary information that was used by the NRC staff during its reviews. The information that was confirmed by order is that information that directly corresponds to NUREG-0737 requirements or alternatives offered by a licensee).

The post-TMI requirements described in NUREG-0737 are a major source of the differences or inconsistencies in the licensing bases for nuclear power plants. Post-TMI requirements were imposed by order for those plants licensed at the time of the accident. The orders differ from each other in terms of stressing the technical aspects of modifications or the schedules associated with implementing the modifications. Some of the requirements or only parts of a specific NUREG-0737 item were subsequently incorporated into TS. Plants undergoing licensing near the time of TMI may have license conditions related to the post-TMI requirements. Some later plants had the post-TMI requirements reviewed as part of the original licensing process and the subjects are only discussed in the updated FSAR (and therefore controlled under 10 CFR 50.59 and 50.71, see next section on Mandated Licensing Bases Documents). When the staff is considering a plant-specific change or a generic change to an item included in NUREG-0737, they need to consider the variations in how the requirements were implemented and ensure that they use the correct mechanism or combination of mechanisms to effect the desired change. Note that the NRC has approved some license amendments for NUREG-0737 items that had been confirmed by order to revise the control mechanism to 10 CFR 50.59. The staff should take care in assigning control of severe accident matters, which are the subject of some NUREG-0737 requirements, to 10 CFR 50.59 (the criteria in 10 CFR 50.59 are based on traditional design-bases transients and accidents). As with other decisions on controlling licensing bases, the staff and agency stakeholders should consider the various elements of the licensing bases, the attributes of the various elements, and select (or create a new element) that best serves the goals of the NRC.

2.3 - Orders	
Characteristics	**Discussion**
Regulatory Basis	Regulatory requirements related to orders are contained in 10 CFR 2.202, "Orders," and 10 CFR 2.205, "Civil Penalties." Regulatory requirements related to gathering information to consider whether an order should be issued are contained in 10 CFR 2.204, "Demand for Information."
Location of Licensing Bases Information	The language in the order should contain that information that the staff wishes to establish as the licensing bases. Some background material, history, or other discussions may be contained in incoming correspondence (referenced in the confirmatory orders) or in other documents related to the order.
Nonconformances and Unplanned Changes	Unless the deviation results in entry into a technical specification action statement, unplanned deviations from orders are handled similar to regulations and license conditions.

	Discovered noncompliances or temporary deviations from orders that define requirements on specific SSCs are usually handled in accordance with a licensee's corrective action program. Plant operation is actually governed by any associated technical specifications and evaluations regarding the safety significance of the problem. The licensing bases are usually not affected and the noncompliance is addressed within the licensee's correction action program and the NRC's enforcement and oversight programs. Generic Letter 91-18 provides guidance on addressing degraded and nonconforming conditions. Discovered noncompliances or other temporary deviations from orders that do not define requirements on specific SSCs or operating practices governed by license conditions or technical specifications are handled within the licensee's correction action program and the NRC's enforcement and oversight programs. The licensing bases are usually not affected by such conditions.
Planned or routine change-control	There are two mechanisms for changing or modifying an existing order. The licensee may request the change by submitting an amendment in accordance with 10 CFR 50.90, "Application for amendment of license or construction permit." (This practice reflects that a condition in operating licenses incorporates orders of the Commission and that a change in an order can be handled as a change to that license condition). The staff will process the request in the same way that it processes a change to a condition included explicitly in the license. The licensee could also request that the NRC issue an order to modify the requirements of another order. In addition, the staff may modify an order on its own initiative without a request from the licensee. In both instances, the staff must follow the guidance in 10 CFR 2.202 when issuing the modified order. If a proposed change affects both an order and TS, the amendment can address both requirements (e.g., some post-TMI requirements were imposed by order but were subsequently incorporated (in whole or in part) into technical specifications). The SE for the amendment can simply state that redundant requirements exist (technical specifications and an order) and that the amendment covers both.
Reporting of changes to the NRC	There is no specific reporting requirements for unplanned deviations from most orders. The problem may be reportable due to criteria included in other reporting requirements (e.g., 10 CFR 50.73).

	Prior NRC approval is required for planned changes to an order.
NRC Verification or Monitoring	Ensuring that licensees comply with orders and other obligations is normally performed as part of the NRC inspection program. See the NRC Inspection Manual for additional information.
Enforcement Practices	Noncompliance with an order is evaluated in accordance with the NRC's inspection and enforcement programs. The appropriate response, from non-cited violation through escalated enforcement action, considers several factors, including the safety significance of the violation. See NRC Enforcement Manual.
Public Participation	Applications for a revision to an order, the staff's issuance or denial of the revision, as well as any information important to the staff's decision-making process are available for public review. In the case where the revision is requested in the form of an amendment to the license, the process and opportunities for public participation are the same as those described in Section 2.2.1, Operating Licenses. In the case where an order is revised through issuance of a revised or new order, the public is provided with an opportunity to request a hearing (see 10 CFR 2.202, "Orders.")
NRC Staff Guidance	NRC Enforcement Manual

3. Mandated Licensing Bases Documents

Mandated Licensing Bases Documents are those documents, such as the updated FSAR, the quality assurance program, the security plan, and the emergency plan, for which the NRC has established requirements for content, change control and reporting. What information should be included in these documents is specified in applicable regulations and regulatory guides. The change control mechanisms and reporting requirements are defined by regulations such as 10 CFR 50.59, 50.54, and 50.71. Those elements of the licensing bases that are addressed in this section include:

3.1 Final Safety Analysis Reports
3.1.1 Design Bases
3.1.2 Technical Requirements Manuals
3.2 Technical Specification Bases Sections
3.3 Quality Assurance Plans
3.4 Security Plans
3.5 Emergency Preparedness Plans
3.6 Fire Protection Plans
3.7 Offsite Dose Calculation Manual
3.8 Core Operating Limits Report
3.9 Pressure/Temperature Limits Report

3.1 - Final Safety Analysis Report (FSAR)

The FSAR is the principal document upon which the NRC bases its safety evaluation supporting the issuance of an operating license (OL) for a nuclear power plant. The updated Final Safety Analysis Report (updated FSAR or UFSAR) incorporates changes made to the FSAR in accordance with 10 CFR 50.71(e). The UFSAR serves as a major source of information on the current plant design and supporting analyses.

Regulatory requirements related to the FSAR are contained in 10 CFR 50.34(b), "Final safety analysis report." The FSAR contains information that describes the facility, presents the design bases and the limits on plant operation, and presents a safety analysis of the structures, systems and components and of the facility as a whole. Regulatory requirements related to the updating and submittal of the FSAR are contained in 10 CFR 50.71(e), "Maintenance of records, making of reports," and 10 CFR 50.4(b)(6), "Updated FSAR." Guidance for the organization and content of FSARs is provided in Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants, LWR Edition." Guidance regarding the content of FSARs and updating requirements is provided in Regulatory Guide 1.181, "Content of the Updated Final Safety Analysis Report in Accordance with 10 CFR 50.71(e)."

The change control process for updated FSARs needs to balance the fact that the FSAR was the principal document supporting the initial licensing of a facility, and the practical needs for licensees to make changes to SSCs and programs described in the updated FSAR. The requirements in 10 CFR 50.59 include those for reporting changes to the NRC and criteria for determining when a proposed change warrants NRC approval. The provisions in 10 CFR 50.59 have involved some controversy and have recently been the subject of staff and industry initiatives. The work culminated in a revision to 10 CFR 50.59 and related guidance documents. See Regulatory Guide 1.187, "Guidance for Implementation of 10 CFR 50.59, 'Changes, Tests and Experiments'," and Revision 1 of NEI 96-07, "Guidelines for 10 CFR 50.59 Evaluations," dated November 2000.

3.1 - Updated Final Safety Analysis Reports	
Characteristic	**Discussion**
Regulatory Basis	The general requirements governing the content of FSARs to support initial licensing are in 10 CFR 50.34. The change control and reporting requirements are in 10 CFR 50.59 and 10 CFR 50.71.
Location of Licensing Bases Information	The licensing bases for this element is contained in the volumes of the most recently updated FSAR. The updated FSAR may also incorporate other documents by reference.
Nonconformances and Unplanned Changes	Whenever degraded or nonconforming conditions of the plant's safety-related systems, structures, or components are identified, Appendix B of 10 CFR Part 50 requires corrective action to correct or resolve the condition. Generic Letter 91-18, "Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and On Operability," provides guidance on the appropriate actions that should be taken when a licensee discovers that its plant does not conform to its updated FSAR. The generic letter also provides guidance as to when a change or deviation should, due to the expected duration of the condition, be evaluated as a planned or long-term change. The guidance in NEI 96-07 also addresses the relationship between maintenance activities (generally controlled in accordance with the maintenance rule) and changes requiring an evaluation in accordance with 10 CFR 50.59.
Planned or routine change control	At any time, a licensee may, in accordance with 10 CFR 50.59, change the design of its plant as described in the updated FSAR. The licensee evaluates changes to the facility and procedures that are described in the updated FSAR using the criteria in 10 CFR 50.59. If the licensee concludes that the change does not exceed the criteria defined in 10 CFR 50.59, the change can be made without prior NRC approval. If the change exceeds one or more of the criteria in 10 CFR 50.59, then the licensee must submit an application to the NRC in accordance with

	10 CFR 50.90 and the NRC must issue a license amendment prior to the implementation of the proposed change. It is important to remember that the criteria in 10 CFR 50.59 are intended to define when a change to the licensing bases are significant enough to warrant a licensing action. The criteria in 10 CFR 50.59 should not be interpreted as safety standards or confused with the technical standards that may ultimately be used to evaluate a license amendment request for a change to the facility as described in the updated FSAR that requires prior NRC approval.
Reporting of changes to the NRC	If the change does not require prior NRC approval or involve a change to a TS, the licensee may implement it and submit a report in accordance with 10 CFR 50.59 which contains a brief description of the change. This report may be submitted at the maximum interval defined in the rule (i.e., 24 months) or along with the FSAR updates required by 10 CFR 50.71(e), or at shorter intervals determined by the licensee. In addition to a report on individual changes required by 10 CFR 50.59, licensees must also submit periodic updates of the FSAR. Initial updates are required within 24 months of the date of issuance of the operating license, with subsequent updates submitted either annually or within 6 months following a refueling outage. The interval between successive updates cannot exceed 24 months and the update must reflect all changes to the plant up to a maximum of 6 months prior to the date of filing. See Regulatory Guide 1.181, "Content of the Updated Final Safety Analysis Report in Accordance with 10 CFR 50.71(e)," and Revision 1 of NEI 98-03, "Guidelines for Updating Final Safety Analysis Reports," for additional details.
NRC Verification or Monitoring	The NRC assesses how licensees are maintaining their facilities and related procedures consistent with the updated FSAR as part of the NRC inspection program. NRR assesses the licensees' submittals of various parts of the licensing bases to ensure consistency and a general compliance with requirements of content, timing, etc.
Enforcement Practices	Noncompliance with the updated FSAR is evaluated in accordance with the NRC's inspection and enforcement programs. The appropriate response, from non-cited violation through escalated enforcement action, considers several factors, including the safety significance of the violation. Specific guidance for departures from the descriptions in FSARs is provided in the Enforcement Manual, NUREG/BR-0195, Section 8.1.3, "Enforcement of 10 CFR 50.59 and Related FSAR."

Public Participation	The updated FSAR is public record. The periodic reports required by 10 CFR 50.59 and 50.71 are likewise available for public review. If an evaluation performed in accordance with 10 CFR 50.59 concludes that a proposed change requires prior NRC approval, a licensee submits an application for a license amendment in accordance with 10 CFR 50.90. See Section 2.2.1, Licenses, for additional details.
NRC Staff Guidance	Regulatory Guides 1.181, 1.186, 1.187

3.1.1 - Design Bases

Design Bases is a term used in several rules in 10 CFR, including 10 CFR 50.34 for content of FSARs, Appendix A on the GDC, and Appendix B on quality assurance. The definition included in 10 CFR 50.2 is:

> Design bases means that information which identifies the specific functions to be performed by a structure, system, or component of a facility, and the specific values or ranges of values chosen for controlling parameters as reference bounds for design. These values may be (1) restraints derived from generally accepted "state of the art" practices for achieving functional goals, or (2) requirements derived from analysis (based on calculation and/or experiments) of the effects of a postulated accident for which a structure, system, or component must meet its functional goals.

In the context of the licensing bases, the design bases are a subset of that information included in the FSAR (see 10 CFR 50.34). The design bases are given specific attention in this OL because of the long-standing issues associated with the terminology. See Regulatory Guide 1.186, "Guidance and Examples for Identifying 10 CFR 50.2 Design Bases," and Appendix B (Dated November 27, 2000) to NEI 97-04, "Design Bases Program Guidelines," for additional discussions. The reporting requirements in 10 CFR 50.72 and 50.73 included a criterion for "outside of the design bases" which was removed during the most recent revision of those rules. The staff should consult NUREG-1022, "Event Reporting Guidelines: 10 CFR 50.72 and 50.73," for additional information regarding the reportability of events and conditions.

The term design bases, as it is used here as a subset of the licensing bases, should not be confused with the term as it is often used in the context of specific functional requirements for SSCs. The functional requirements may or may not be "design bases" and be included in the updated FSAR. The NRC recognized the multiple uses of the terminology and introduced the term "engineering design bases" in NUREG 1397, "An Assessment of Design Control Practices and Design Reconstitution Programs in the Nuclear Power Industry." The engineering design bases covers the broad scope of technical and operational requirements that are applied to SSCs. The engineering design bases for safety-related SSCs is controlled in accordance with Appendix B, Criterion 3, "Design Control." Much of the engineering design bases information resides on site and the specifics are not part of the licensing bases. The definition of engineering design bases that is included in NUREG-1397 is as follows:

Engineering Design Bases: The entire set of design constraints that are implemented, including those that are (1) part of the current licensing bases and form the bases for the staff's safety judgements and (2) those that are not included in the current licensing bases but are implemented to achieve certain economies of operation, maintenance, procurement, installation, or construction.

3.1.2 - Technical Requirements Manual

Many licensees created a document entitled the Technical Requirements Manual (TRM) (other names are used by some licensees) to contain those technical specifications provisions relocated from the Technical Specifications following issuance of the NRC's final policy statement on Technical Specifications and subsequent revision of 10 CFR 50.36. The basic principle behind the TRM is that it facilitates the relocation amendment(s) by providing a clear destination and control mechanism for the requirements removed from the technical specifications. The staff and licensees agreed that the relocated requirements were to be controlled using the criteria in 10 CFR 50.59. The parties did not, however, always make clear that the TRM was to be part of the updated FSAR such that the TRM was legally within the scope of 10 CFR 50.59 and 50.71. The staff and licensees may take advantage of future opportunities to clearly state that the TRM is part of the updated FSAR or is incorporated by reference into the updated FSAR.

3.1.2 - Technical Requirements Manual	
Characteristic	**Discussion**
Regulatory Basis	It was intended that upon relocation of the TS provisions, they would be under the controls of 10 CFR 50.59 and 50.71. Some early TRMs may not have captured this intent and may be controlled in accordance with licensee commitment management programs (i.e., the licensee made a regulatory commitment to control the TRM using evaluation criteria in 10 CFR 50.59 but the reporting requirements may be unclear). Some plants have programmatic controls for the TRM within the administrative controls section of the TS.
Location of Licensing Bases Information	The Technical Requirements Manual (or equivalent if a licensee uses different terminology). The desired state is that the TRM is a volume of the updated FSAR or is incorporated by reference into the updated FSAR. This may not be the case for some of the earlier TRMs.
Nonconformances and unplanned changes	Whenever degraded or nonconforming conditions of the plant's safety-related systems, structures, or components are identified, Appendix B of 10 CFR Part 50 requires corrective action to correct or resolve the condition. Generic Letter 91-18, "Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and On Operability," provides guidance on the appropriate actions that should be taken when a licensee discovers that its plant does not conform to its updated FSAR. The generic letter

	also provides guidance as to when a change or deviation should, due to the expected duration of the condition, be evaluated as a planned or long-term change. The TRMs have often maintained the format and language of the technical specifications limiting conditions for operation of the relocated requirement. There should be no confusion that this practice was a matter of convenience and that action statements or other aspects of the TRM can be changed by licensees using the process defined in 10 CFR 50.59. This includes those relocated provisions that defined allowable outage times or required actions, including plant shutdowns. Note that some of the relocated TS provisions included special reporting requirements. The determination that the reports were not required was inherent in the staff's findings that the provisions could be relocated.
Planned or routine change-control	At any time, a licensee may, in accordance with 10 CFR 50.59, change the design of its plant as described in the updated FSAR (including the TRM). The licensee evaluates changes to the facility and procedures that are described in the updated FSAR using the criteria in 10 CFR 50.59. If the licensee concludes that the change does not exceed the criteria defined in 10 CFR 50.59, the change can be made without prior NRC approval. If the change exceeds one or more of the criteria in 10 CFR 50.59, then the licensee must submit an application to the NRC in accordance with 10 CFR 50.90 and the NRC must issue a license amendment prior to the implementation of the proposed change. The format of many TRMs (similar to relocated technical specifications requirements) was done for convenience and does not change the fact that the contents are controlled as part of the updated FSAR.
Reporting of Changes to the NRC	If the change does not require prior NRC approval, the licensee may implement the change without consulting with the staff. Reporting of changes to the TRM should be part of the reports submitted in accordance with 10 CFR 50.59 and 10 CFR 50.71 (or submitted separately if the TRM is incorporated by reference instead of being treated as a volume of the updated FSAR). The reporting requirements for some of the earlier issued TRMs may be unclear. The staff should work with licensees to ensure that there is mutual understanding of the treatment of the TRM and, if possible, to have the TRM be part of the updated FSAR or be incorporated by reference in the updated FSAR.
NRC Verification or Monitoring	The NRC assesses how licensees are maintaining their facilities and related procedures consistent with the updated FSAR (including the TRM) as part of the NRC inspection program. The staff should work, as necessary, with regional counterparts to ensure mutual understanding that the TRM is part of (or at least treated as part of) the updated FSAR.

	NRR assesses the licensees' submittals of various parts of the licensing bases to ensure consistency and a general compliance with requirements of content, timing, etc.
Enforcement Practices	See 3.1 for updated FSAR
Public Participation	See 3.1 for updated FSAR
NRC Staff Guidance	See 3.1 for updated FSAR

3.2 - Technical Specification Bases Section

Each licensee is required by 10 CFR 50.36, "Technical specifications" to include in their applications for a license the bases or reasons (e.g., a bases section) for technical specifications (except for administrative controls). The rule also states that the bases shall not become part of the technical specifications and does not provide for the control or updating of the bases. This has led to some confusion and inconsistencies in the practices of licensees and the staff regarding changes to the bases section of TS.

3.2 - Technical Specification Bases Section	
Characteristics	**Discussion**
Regulatory Basis	Licensees are required to provide a bases for TS by 10 CFR 50.36. This has traditionally been met by the creation of a bases section for TS. The rule does not dictate format or have provisions for change-control or reporting for the bases (other than to state that the provisions are not those for the TS themselves). The iSTS include an administrative requirement to control TS bases using the criteria of 10 CFR 50.59 and to report changes on a schedule similar to the FSAR update process. This process is gradually being adopted by the staff and licensees for application to non-iSTS plants.
Location of Licensing Bases Information	The bases sections of TS are sometimes integral to TS sections (e.g., a bases discussion follows each specification), sometimes included as separate sections within a single volume, or included as a separate volume of multiple-volume TS (i.e., the iSTS format).
Nonconformances and Unplanned Changes	Whenever degraded or nonconforming conditions of the plant's safety-related systems, structures, or components are identified, Appendix B of 10 CFR Part 50 requires corrective action to correct or resolve the condition.

	Generic Letter 91-18 provides guidance on the appropriate actions that should be taken when a licensee discovers that its plant does not conform to the bases of a TS. Failure to comply with the bases of a TS could lead to the equipment being considered inoperable and require entry into the action statements of the associated LCO.
Planned or routine change control	For those licensees controlling the bases section in accordance with 10 CFR 50.59, they may apply the rule to change the design of a plant as described in the updated FSAR or the bases of the TS. If the licensee concludes that the change does not exceed the criteria defined in 10 CFR 50.59, the change can be made without prior NRC approval. If the change exceeds one or more of the criteria in 10 CFR 50.59, then the licensee must submit an application to the NRC in accordance with 10 CFR 50.90 and the NRC must issue a license amendment prior to the implementation of the proposed change.
Reporting of changes to the NRC	Licensees have traditionally included TS bases changes along with related amendments. Non-iSTS plants have also submitted changes to bases when no amendment was required in order to have the NRC issue the revised bases pages (this was done because the bases pages are included in the TS while the bases for iSTS are maintained in a separate volume). Increasingly, all licensees are submitting TS bases changes in a manner similar to the updated FSAR (schedule similar to 10 CFR 50.71(e)). If a licensee were to evaluate a bases change using the criteria of 10 CFR 50.59 and determine that prior NRC approval was required, an application to amend the operating license would be required (see 3.1 on attributes of the updated FSAR).
NRC Verification or Monitoring	The NRC assesses how licensees are maintaining their facilities and related procedures consistent with the updated FSAR and TS bases as part of the NRC inspection program. NRR assesses the licensees' submittals of various parts of the licensing bases to ensure consistency and a general compliance with requirements of content, timing, etc.
Enforcement Practices	see 3.1 on updated FSAR
Public Participation	see 3.1 on updated FSAR
NRC Staff Guidance	

3.3 - Quality Assurance Program

Each licensee is required by regulations to have a quality assurance program that satisfies the requirements of Appendix B to 10 CFR Part 50. The scope of the programs are limited to safety-related SSCs (and non-safety related equipment that may be included in an augmented program). The programs consist of processes, organizations, and procedures to meet the various requirements of Appendix B. The programs will often reference industry codes and standards, regulatory guides, and other documents that have been developed to ensure that the SSCs are designed, constructed, procured, and maintained such that there is a high confidence that the safety-related SSCs will perform their safety function under design conditions.

3.3 - Quality Assurance Program	
Characteristic	**Discussion**
Regulatory Basis	10 CFR 50.34(b)(6)(ii) requires licensees to provide as part of the updated FSAR information on how the applicable requirements of Appendix B would be satisfied at the facility requesting an operating license. 10CFR 50.54(a) requires each licensee to implement the program described or referenced in the updated FSAR. 10 CFR 50.54(a) also describes the change control and reporting characteristics for QA programs. Appendix B includes requirements that apply to all activities affecting the safety-related functions of SSCs.
Location of Licensing Bases Information	The quality assurance program is described in a document that is either considered to be part of the updated FSAR or referenced by the updated FSAR and maintained as a separate document.
Nonconformances and Unplanned Changes	Discovered noncompliances or temporary deviations from the QA requirements that might affect specific SSCs are usually handled in accordance with a licensee's corrective action program. Plant operation is actually governed by any associated license conditions, technical specifications and evaluations regarding the safety significance of the problem. The licensing bases are usually not affected and the noncompliance is addressed within the licensee's correction action program and the NRC's enforcement and oversight programs. Generic Letter 91-18 provides guidance on addressing degraded and nonconforming conditions. Discovered noncompliances or other temporary deviations from regulations that do not define requirements on specific SSCs or

	operating practices governed by license conditions or technical specifications are handled within the licensee's correction action program and the NRC's enforcement and oversight programs. The licensing bases are usually not affected by such conditions.
Planned or routine change control	The change-control process for QA programs is defined in 10 CFR 50.54(a). The licensee is required to evaluate changes to the QA program and determine if the change reduces the commitments in the program description as accepted by the NRC (note the term commitment in this rule is different from "regulatory commitment" that is discussed in Section 4). Criteria are provided in 10 CFR 50.54(a) to help determine if a change should be considered a reduction in commitment (these include the use of NRC-approved QA standards and alternatives approved by an NRC safety evaluation). If the change is not a reduction in commitment, the licensee may implement without consulting the NRC staff. Changes that are determined to be a reduction in commitment need to be submitted to the NRC and receive NRC approval prior to implementation. The recently revised 10 CFR 50.59 makes clear that programs such as the QA program that are subject to specific change-control rules [e.g., 10 CFR 50.54(a)] do not need to be evaluated against the criteria of 10 CFR 50.59 even though the programs may be part of or incorporated by reference into the updated FSAR.
Reporting of changes to the NRC	Licensees report changes that are not a reduction in commitment in accordance with the FSAR update requirements (10 CFR 50.71(e)). Licensees request NRC review and approval of changes that are reductions in commitments prior to implementing the change.
NRC Verification or Monitoring	The NRC assesses how licensees are complying with their QA programs as part of the NRC inspection program. NRR assesses the licensees' submittals of QA program updates and reviews changes that are reductions in commitments to either approve or deny the proposed change prior to implementation.
Enforcement Practices	Noncompliance with the requirements of Appendix B or a specific QA program is evaluated in accordance with the NRC's inspection and enforcement programs. The appropriate response, from non-cited violation through escalated enforcement action, considers several factors, including the safety significance of the violation. Specific guidance for departures from the descriptions in updated FSARs is provided in the Enforcement Manual, NUREG/BR-0195, Section 8.1.5, "Citations Against 10 CFR 50, Appendix B."

Public Participation	The QA Program is a public record. The periodic updates required by 10 CFR 50.54(a) are likewise available for public review. If an evaluation performed in accordance with 10 CFR 50.54(a) concludes that a proposed change requires prior NRC approval, a licensee submits a request for NRC review and approval prior to implementation. Correspondence and meetings associated with these reviews are public. No specific opportunity to comment or to request an adjudicatory proceeding are provided for licensee-specific reviews.
NRC Staff Guidance	

3.4 - Emergency Preparedness Program

Following the accident at Three Mile Island in 1979, the Nuclear Regulatory Commission (NRC) reexamined the role of emergency planning for protection of the public in the vicinity of nuclear power plants. The Commission issued regulations requiring that before a plant could be licensed to operate, the NRC must have "reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency." The regulations set forth 16 emergency planning standards and define the responsibilities of licensees and State and local organizations involved in emergency response.

For planning purposes, the Commission has defined a plume exposure pathway emergency planning zone (EPZ) consisting of an area about 10 miles in radius and an ingestion pathway EPZ about 50 miles in radius around each nuclear power plant. EPZ size and configuration may vary in relation to local emergency response needs and capabilities as affected by such conditions as demography, topography, land characteristics, access routes, and jurisdictional boundaries. Detailed information about emergency planning and preparedness is contained in Appendix E of 10 CFR Part 50 and in NUREG-0654 (FEMA-REP-1), a joint publication of the NRC and the Federal Emergency Management Agency (FEMA) entitled "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants."

For each reactor site, there are onsite and offsite emergency plans to assure that adequate protective measures are taken to protect the public in the event of a radiological emergency. Federal oversight of emergency planning for licensed nuclear power plants is shared by the NRC and FEMA through a memorandum of understanding. The memorandum is responsive to the President's decision of December 7, 1979, that FEMA will take the lead in offsite planning and response, that NRC assist FEMA in carrying out this role, and considering the NRC's continuing statutory responsibility for the radiological health and safety of the public. Each licensee exercises its emergency plan with offsite authorities so that State and local government emergency plans for each operating reactor site are exercised biennially, with participation of State and local governments, within the plume exposure EPZ.

3.4 - Emergency Preparedness Program	
Characteristics	**Discussion**
Regulatory Basis	10 CFR 50.34(b)(v) requires licensees to include emergency plans as part of the FSAR submitted for initial licensing. 10 CFR 50.47, Emergency plans, states that an operating license will not be issued without a finding by the NRC that there is reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency. The rule defines standards for onsite and offsite emergency plans. 10 CFR 50.54(q) requires each licensee to follow and maintain in effect emergency plans that satisfy 10 CFR 50.47 and 10 CFR 50, Appendix E. The rule also defines the change-control process (the decrease in effectiveness standard) and the requirements for reporting of changes to the NRC. Requirements for licensees to submit to the NRC state and local emergency plans is contained in 10 CFR 50.54(s). Licensees are required by 10 CFR 50.54(t) to perform periodic reviews of their emergency plans. Appendix E establishes the minimum requirements for emergency plans.
Location of Licensing Bases Information	The licensing bases for emergency plans is provided by the applicable regulations and the site-specific emergency plan. Details of how a licensee implements its emergency plan is provided in Emergency Plan Implementing Procedures (EPIPs) which are submitted to the NRC (for information).
Nonconformances and Unplanned Changes	Discovered noncompliances or temporary deviations from the emergency plan are addressed in accordance with 10 CFR 50.54(t) and provisions within the plan.
Planned or routine change control	The change-control process for emergency plans is defined in 10 CFR 50.54(q). The licensee is required to evaluate changes to the emergency plan and determine if the change involves a decrease in the effectiveness of the plan. If the change does not involve a decrease in effectiveness, the licensee may implement the change without consulting the NRC staff. Changes that are determined to involve a decrease in effectiveness must be be submitted to the NRC and receive NRC approval prior to implementation. The recently revised 10 CFR 50.59 makes clear that programs such as the emergency plan that are subject to specific change-control rules (e.g., 10 CFR 50.54(q)) do not need to be evaluated against the criteria

	of 10 CFR 50.59 even though the programs may be part of or incorporated by reference into the FSAR.
Reporting of changes to the NRC	Licensees report (as specified in 10 CFR 50.4) changes that are not a decrease in effectiveness within 30 days after the change is made. Licensees request NRC review and approval of changes that are determined to involve a decrease in effectiveness prior to implementing the change.
NRC Verification or Monitoring	The NRC assesses how licensees are complying with their emergency plans as part of the NRC inspection program. NRR and regional offices assess the licensees' submittals of emergency plan changes that do not require prior NRC approval and NRR reviews changes that involve decreases in effectiveness to either approve or deny the proposed change prior to implementation.
Enforcement Practices	Noncompliance with the requirements of 10 CFR 50.47, Appendix E or a specific emergency plan is evaluated in accordance with the NRC's inspection and enforcement programs. 10 CFR 50.54(s) defines a process for the NRC's response if it does not have reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency. The rule generally allows four months for the findings to be corrected before considering whether the reactor should be shut down or determining if other enforcement actions are appropriate. See Enforcement Manual for additional information.
Public Participation	The emergency plan is maintained as a public record. The periodic updates required by 10 CFR 50.54(q) are likewise available for public review. If an evaluation performed in accordance with 10 CFR 50.54(q) concludes that a proposed change requires prior NRC approval, a licensee submits a request for NRC review and approval prior to implementation. Correspondence and meetings associated with these reviews are public. No specific opportunity to comment or to request an adjudicatory proceeding are provided for licensee-specific reviews.
NRC Staff Guidance	

3.5 - Security Plan

The NRC decided in 1977 that, although there was no known threat directed against nuclear power reactors, it would be prudent to have security programs in place. Since then, the programs have matured, technology has improved, and licensees have become more proficient in achieving security program goals. Security program requirements for nuclear power plants are contained in 10 CFR Part 73 of NRC's regulations. 10 CFR 73.55(a) requires licensees to establish a physical protection system and a security organization with the objective of providing high assurance that activities involving special nuclear material are not inimical to the common defense and security and do not constitute an unreasonable risk to the public health and safety. The physical protection system is required to protect against the design bases threat (DBT) of radiological sabotage (as defined in 10 CFR 73.1) and to "include, but not necessarily be limited to, the capabilities to meet the specific requirements contained in paragraphs [73.55] (b) through (h)."

3.5 - Security/Safeguards Program	
Characteristics	**Discussion**
Regulatory Basis	Licensees are required to develop physical security plans (PSPs) in accordance with 10 CFR 73.55(a) to satisfy the requirements of 10 CFR 73.55(a) and (b) through (h). These plans are submitted to the NRC for approval before implementation. Requirements for evaluating changes to security plans and conducting periodic audits of security plans are defined in 10 CFR 50.54(p).
Location of Licensing Bases Information	The licensing bases information is contained within the applicable regulations and the site-specific security plans. Requirements to maintain security programs are also commonly included as conditions in operating licenses.
Nonconformances and Unplanned Changes	Upon discovery of a nonconformance with their security plan, licensees restore compliance, implement compensatory actions, or otherwise take actions as called for by provisions within their security plan.
Planned or routine change control	Changes to approved PSPs that do not decrease the effectiveness of the plan can be made through 10 CFR 50.54(p) and can be implemented without prior NRC approval; changes that do decrease the effectiveness of the plan are made under 10 CFR 50.90 and require NRC approval before implementation. Generic Letter 95-08, "10 CFR 50.54(p) Process for Changes to Security Plans Without Prior NRC Approval," provides guidance regarding the determination of whether a proposed change involves a decrease in effectiveness of the security plan.
Reporting of changes to the NRC	Licensees report (as specified in 10 CFR 50.4) changes that are not a decrease in effectiveness within two months after the change is made. Licensees request NRC review and approval of changes that are determined to involve a decrease in effectiveness prior to implementing the change.

NRC Verification or Monitoring	The NRC assesses how licensees are complying with their security plans as part of the NRC inspection program. NRR and regional offices assess the licensees' submittals of security plan changes that do not require prior NRC approval and NRR reviews changes that involve decreases in effectiveness to either approve or deny the proposed change prior to implementation.
Enforcement Practices	Noncompliance with the requirements of 10 CFR Part 73 or a specific security plan is evaluated in accordance with the NRC's inspection and enforcement programs. Specific guidance for security issues is provided in the Enforcement Manual, NUREG/BR-0195, Section 8.3, "Safeguards."
Public Participation	Much of the information associated with security plans is withheld from public disclosure. Cover letters and other nonclassified information is usually available to provide a limited amount of information. Changes to the security plan that involve a decrease in effectiveness are processed as a license amendment in accordance with 10 CFR 50.90 with the associated public notices and opportunities for requests for hearings.
NRC Staff Guidance	

3.6 - Fire Protection

The primary objective of fire protection programs at U.S. commercial nuclear power plants is to minimize both the probability of occurrence and consequences of fire. To meet this objective, the fire protection programs are designed to provide reasonable assurance, through defense-in-depth, that a fire will not prevent the performance of necessary safe shutdown functions and will not significantly increase the risk of radioactive releases to the environment.

The Commission's requirements for nuclear plant fire protection programs are promulgated in a number of regulations and supporting guidelines, including, but not limited to, General Design Criterion (GDC) 3, 10 CFR 50.48, 10 CFR 50 Appendix R, generic communications (e.g., generic letters, bulletins, regulatory issue summaries, and information notices), NUREG reports, the Standard Review Plan (NUREG-0800), Branch Technical Positions, and industry consensus standards.

3.6 - Fire Protection Program	
Characteristic	**Discussion**
Regulatory Basis	General Design Criterion 3, "Fire Protection," requires that structures, systems, and components important to safety be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. 10 CFR Part 50.48 requires that each operating nuclear power plant have a fire protection plan that satisfies GDC 3. It specifies what should be contained in such a plan and lists the basic fire protection guidelines for the plan. Section 50.48 also requires that all plants with operating licenses prior to January 1, 1979 satisfy the requirements of Section III.G, III.J and III.O, and other sections of 10 CFR 50, Appendix R where approval of similar features had not been obtained prior to the effective date of Appendix R. 10 CFR Part 50, Appendix R, applies to licensed nuclear power electric generating stations that were operating prior to January 1, 1979, except as noted in 10 CFR 50.48(b). With respect to certain generic issues for such facilities, Appendix R identifies fire protection features required to satisfy Criterion 3 of Appendix A.
Location of Licensing Bases Information	The licensing bases associated with fire protection are contained in the applicable regulations, the license condition associated with the Fire Protection Program, and the Fire Protection Program itself. Some licensees may incorporate by reference the Fire Protection Program into a facility's FSAR.
Nonconformances and Unplanned Changes	Upon discovery of a nonconformance with their fire protection program, licensees restore compliance, implement compensatory actions, or otherwise take actions as called for by provisions within their fire protection program. Fire protection equipment may also be included as an augmented program within a licensee's QA Program. If so, the QA program may have provisions to address nonconformances with the Fire Protection Program.
Planned or routine change control	If a licensee determines that a proposed configuration of SSC(s) or a proposed procedure does not comply with the requirements of the applicable regulations, the licensee may request an exemption using the provisions of 10 CFR 50.12. In terms of changes to the fire protection program, the standard license condition for fire protection was transmitted to licensees in April of 1986 as part of Generic Letter 86-10. The standard license condition reads as follows:

	<u>Fire Protection</u> "(Name of Licensee) shall implement and maintain in effect all provisions of the approved fire protection program as described in the Final Safety Analysis Report for the facility (or as described in submittals dated ---------) and as approved in the SER dated ----------(and Supplements dated ---------) subject to the following provision: "The licensee may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire." Those licensees that include the Fire Protection Program in the FSAR (by incorporation by reference) and do not have a license condition that defines the change-control criteria, use the criteria in 10 CFR 50.59 to evaluate changes to the NRC-approved program. If the fire protection requirement is included in the license, the criterion in the license condition is used and criteria in 10 CFR 50.59 are not.
Reporting of changes to the NRC	Licensees maintain on site the changes to their fire protection program that do not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire and the changes are subject to NRC inspection. Those licensees that include the fire protection program as part of the FSAR submit updates in accordance with 10 CFR 50.71(e). Licensees seeking an exemption from a requirement in Appendix R or other rule must submit a formal request (see 10 CFR 50.12 and 50.4) to the NRC for review.
NRC Verification or Monitoring	The NRC assesses how licensees are complying with their fire protection program as part of the NRC inspection program.
Enforcement Practices	Noncompliance with the requirements of fire protection regulations or a specific fire protection program is evaluated in accordance with the NRC's inspection and enforcement programs. Specific guidance for fire protection issues is provided in the Enforcement Manual, NUREG/BR-0195, Section 8.1.7, "Actions Involving Fire Protection."
Public Participation	The original fire protection program that was submitted for NRC approval is available as a public record as are updates made in accordance with 10 CFR 50.71(e). The process for NRC review of a licensee's request for an exemption from a regulation (including Appendix R) uses correspondence that is available for public review. No specific opportunity to comment or to request an adjudicatory proceeding are provided for licensee-specific

	reviews. An environmental assessment and finding of no significant impact is published in the Federal Register shortly before the issuance of an exemption.
NRC Staff Guidance	

3.7 – Offsite Dose Calculation Manual (ODCM)

The importance of the ODCM in terms of it being part of the licensing bases was increased upon the removal of specific radiological effluent technical specifications (RETS) from TSs and the relocation of procedural details of RETS to the ODCM or to the process control program (PCP). The relocation of the RETS involved the creation of administrative controls within TS to govern the control of the ODCM (in terms of licensee reviews and submittals to the NRC). See Generic Letter 89-01 for additional information. Common definitions of the ODCM and PCP are:

The OFFSITE DOSE CALCULATION MANUAL (ODCM) shall contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents, in the calculation of gaseous and liquid effluent monitoring Alarm/Trip Setpoints, and in the conduct of the Environmental Radiological Monitoring Program. The ODCM shall also contain (1) the Radioactive Effluent Controls and Radiological Environmental Monitoring Programs required by Section 6.8.4 and (2) descriptions of the information that should be included in the Annual Radiological Environmental Operating and Semi-annual Radioactive Effluent Release Reports required by Specifications 6.9.1.3 and 6.9.1.4.

The PROCESS CONTROL PROGRAM (PCP) shall contain the current formulas, sampling, analyses, test, and determinations to be made to ensure that processing and packaging of solid radioactive wastes based on demonstrated processing of actual or simulated wet solid wastes will be accomplished in such a way as to assure compliance with 10 CFR Parts 20, 61, and 71, State regulations, burial ground requirements, and other requirements governing the disposal of solid radioactive waste.

3.8 – Core Operating Limits Report (COLR)

The COLR was introduced to the set of licensing bases documents in an attempt to decrease the number of cycle-specific TS changes that were submitted to and reviewed by the NRC. The concept was to maintain TS requirements for the various parameters but to re-locate the cycle-specific limits, such as power distribution limits and control rod position limits, into the COLR (by referencing the COLR in the affected TSs). The COLR was introduced as a line-item improvement to TS by Generic Letter 89-16, "Removal of Cycle-specific Parameter Limits from Technical Specifications."

A common definition for and administrative requirements for controlling the COLR are as follows:

> The CORE OPERATING LIMITS REPORT is the unit-specific document that provides [core] operation limits for the current operating reload cycle. These cycle-specific [core] operating limits shall be determined for each reload cycle in accordance with Specification 6.9.X. Plant operation within these operating limits is addressed in individual specifications.
>
> Core operating limits shall be established and documented in the CORE OPERATING LIMITS REPORT before each reload cycle or any remaining part of a reload cycle. (If desired, the individual specifications that address [core] operating limits may be referenced.) The analytical methods used to determine the [core] operating limits shall be those previously reviewed and approved by NRC in [identify the Topical Report(s) by number, title, and date, or identify the staff's safety evaluation report for a plant-specific methodology by NRC letter and date]. The core operating limits shall be determined so that all applicable limits (e.g., fuel thermal-mechanical limits, core thermal-hydraulic limits, ECCS limits, nuclear limits such as shutdown margin, and transient and accident analysis limits of the safety analysis) are met. The CORE OPERATING LIMITS REPORT, including any mid-cycle revisions or supplements thereto, shall be provided upon issuance, for each reload cycle, to the NRC Document Control Desk with copies to the Regional Administrator and Resident Inspector.

As discussed in Section 6, a uniform treatment of topical reports had not been established at the time that the COLR was created and the list of topical reports was included in the administrative controls section of TS. Licensees and/or the staff may choose to pursue changes to the control of the topical reports used for parameters in the COLR as a result of recent changes to 10 CFR 50.59 and the inclusion of a specific criteria for the control of methodologies described in or incorporated by reference into the updated FSAR. Supplement 1 to Generic Letter 83-11, "Licensee Qualification For Performing Safety Analyses," dated June 24, 1999, provides some additional information related to licensees' analyses of parameters included in the COLR.

3.9 – Pressure Temperature Limits Report (PTLR)

Similar to the COLR, the PTLR was introduced as a licensing bases document in an attempt to decrease the number of TS changes that were submitted to and reviewed by the NRC. The concept was to maintain TS requirements for pressure-temperature limits and low temperature-overpressure (LTOP) limits but to re-locate the age or fluence-specific curves to the PTLR (by referencing the PTLR in the affected TSs). The PTLR was introduced as a line-item improvement to TS by Generic Letter 96-03, "Relocation of the Pressure Temperature Limit and Low Temperature Overpressure Protection Limits," dated January 31, 1996.

A common definition for and administrative requirements for controlling the PTLR are as follows:

Definition:

The PTLR is the unit-specific document that provides the reactor vessel P/T limits and setpoints, including heatup and cooldown rates, for the current reactor vessel fluence period. These P/T limits shall be determined for each fluence period or effective full-power years (EFPYs) in accordance with Specification 5.X.X.X. Plant operation within these operating limits is addressed in LCO 3.X.X, "RCS Pressure and Temperature (P/T) Limits," and LCO 3.X.X, "Low Temperature Overpressure Protection (LTOP) System."

Administrative Controls:

Section 5.X.X.X Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

a. RCS pressure and temperature limits for heatup, cooldown, LTOP, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be established and documented in the PTLR for the following: [The individual specifications that address RCS pressure and temperature limits must be referenced here.]

b. The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following document(s): [Identify the NRC staff approval document(s) by date.]

c. The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluence period or EFPYs and for any revision or supplement thereto.

4 Regulatory Commitments

Regulatory Commitments are explicit statements to take a specific action agreed to, or volunteered by, a licensee and submitted in writing on the docket to the NRC. A regulatory commitment is appropriate for matters in which the staff has a significant interest but which do not warrant either a legally binding requirement or inclusion in the updated FSAR or a program subject to a formal regulatory change control mechanism. Control of such commitments in accordance with licensee programs is acceptable provided those programs include controls for evaluating changes and, when appropriate, reporting them to the NRC.

4 - Regulatory Commitments	
Characteristics	**Discussion**
Regulatory Basis	The term commitment is not defined in regulations but is used in 10 CFR Part 54 definition of current licensing bases and 10 CFR 50.109, "Backfitting." The term is also used in the NRC Enforcement Policy, along with Notice of Deviation, in its discussion of administrative tools.
Location of Licensing Bases Information	Regulatory commitments can be included in various documents submitted by licensees. The commitments are not collected into a single document (although some licensees may have information systems on site that are able to provide a list of items that they have classified as commitments).
Nonconformances and Unplanned Changes	Whenever degraded or nonconforming conditions of the plant's safety-related systems, structures, or components are identified, Appendix B of 10 CFR Part 50 requires corrective action to correct or resolve the condition. Generic Letter 91-18 provides guidance on the appropriate actions that should be taken when a licensee discovers that SSCs are in a degraded or nonconforming condition.
Planned or routine change control	Licensees evaluate changes to regulatory commitments using site specific administrative controls and processes. The NRC has accepted an industry guidance document, NEI 99-04, "Guidelines for Managing NRC Commitments" as providing useful guidance to licensees on controlling regulatory commitments (See SECY-00-045). The NEI guidance document includes review criteria to help licensees determine what, if any, interactions with the NRC staff are appropriate for changes to regulatory commitments.
Reporting of changes to the NRC	NEI 99-04 includes criteria for determining if and when the NRC staff should be informed of a change to a regulatory commitment. Although there is no regulatory requirement for such reports, it is beneficial that licensees use the NEI guidance or similar criteria to report changes to

	regulatory commitments. In order to maintain a reasonable understanding of the total licensing bases for a facility, the NRC staff needs some confidence that changes to the elements, including regulatory commitments, will be periodically provided.
NRC Verification or Monitoring	The NRC inspection program may review a regulatory commitment associated with a particular issue or technical area. In general, however, the inspection program does not assess how well licensees control regulatory commitments. NRR plans to assess the licensees' commitment management programs and their implementation of those programs. This activity will be performed under the DLPM responsibilities for "Other Licensing Tasks."
Enforcement Practices	Noncompliance with a regulatory commitment can result in the issuance of a Notice of Deviation (NOD). Notices of Deviation are written notices describing a licensee's failure to satisfy a commitment where the commitment involved has not been made a legally binding requirement. A Notice of Deviation requests a licensee to provide a written explanation or statement describing corrective steps taken (or planned), the results achieved, and the date when corrective action will be completed. (See Section 4.5, "Notice of Deviation," in the NRC Enforcement Manual) An NOD is useful at the regulatory commitment level of the hierarchy; it is less severe than a notice of violation but still allows the staff to request information from a licensee if the implementation of an action was not consistent with the mutually agreed-upon commitment. If it becomes necessary to force a licensee to comply with a regulatory commitment, the NRC may order a licensee to complete the action.
Public Participation	The documents that include regulatory commitments being made by licensees are in the public record. The periodic reports submitted to describe changes to regulatory commitments are likewise available for public review.
NRC Staff Guidance	NRR Office Letter 900 (to become Office Instruction LIC-105)

5 Non-Licensing Bases or Ancillary Information

In addition to licensing bases information, there is a large amount of information exchanged during routine interactions between the NRC staff and licensees that does not warrant being considered as part of the "licensing bases." Information provided to NRC staff in regional offices or headquarters pertaining to corrective actions for routine problems with plant equipment or procedures would likely fall into this category. The information should be controlled in accordance with normal licensee programs. There should be mutual understanding by licensees and NRC staff that such information may not need to be updated in docketed correspondence.

6 Other Regulatory Processes & Tools

Questions about other regulatory processes often arise during discussions of the licensing bases for operating reactors. A short discussion of some of the more frequently questioned processes is provided below.

6.1 Confirmatory Action Letter (CAL)

CALs are addressed as item (3) in Section VI.E of the Enforcement Policy and in Section 4.7 of the Enforcement Manual. CALs do not establish legally binding requirements. However, failure to meet a commitment in a CAL could be addressed through an NOD. In addition, an order or a Demand For Information could be issued where the licensee's performance, as demonstrated by the failure to meet CAL commitments, does not provide reasonable assurance that the NRC can rely on the licensee to meet the NRC's requirements and protect public health and safety.

CALs are letters issued to licensees or vendors to emphasize and confirm a licensee's or vendor's agreement to take certain actions in response to specific issues. The NRC expects licensees and vendors to adhere to any commitments addressed in a CAL. CALs are normally used for emergent situations where the staff believes that it is not necessary or appropriate to develop a legally binding requirement, in light of the agreed-upon commitment. CALs are flexible and valuable tools available to the staff to resolve licensee issues in a timely and efficient manner.

CALs may be issued to confirm the following types of actions (note that this is not an exhaustive list):

1. In-house or independent comprehensive program audit of licensed activities.
2. Correction of training deficiencies such as radiological safety, licensed operator, etc.
3. Procedural improvements.
4. Equipment maintenance.
5. Equipment operation and safety verification.
6. Voluntary, temporary suspension of licensed activities.
7. Licensee's agreement to NRC approval prior to resumption of licensed activities.
8. Root cause failure analyses.
9. Improved control and security of licensed material.
10. Transfer of licensed material.
11. Future submittal of license amendment request.
12. Commitment to honor an AIT or IIT quarantine request.
13. Specific actions in response to an unsatisfactory operator requalification program.
14. Actions to be taken to regain compliance with Commission requirements, including compensatory actions.

CALs should only be issued when there is a sound technical and/or regulatory bases for the desired actions discussed in the CAL. Specifically, CALs must meet the threshold defined in the Enforcement Policy (i.e., "to remove significant concerns about health and safety, safeguards, or the environment"). In other words, the issues addressed in a CAL should be at a level of significance such that if the licensee did not agree to meet the commitments in a CAL, the staff would likely proceed to issue an order.

Although CALs are considered to be more an enforcement matter than a licensing matter, the individual subjects addressed in a CAL may have some licensing implications. The staff should ensure that any desired change in the licensing bases that is included as an item in a CAL be placed into the most appropriate element of the licensing bases. For example, if the CAL is establishing a long-term regulatory commitment (i.e., a commitment that will be continued after the closeout of the CAL), the staff should ensure that the commitment will be entered into the licensee's commitment management program.

6.2 - Topical Reports

Topical reports are a vehicle to improve the efficiency of a licensing process by allowing the staff to review a methodology or proposal that will be used by multiple licensees and following approval, allowing the participating licensees to reference the approved report.

Under the NRC licensing topical report program, industry organizations may, on their own volition or at the request of the NRC staff, submit reports to the NRC on specific safety-related subjects and have them reviewed independently of any operating license review. The purpose of the program is to minimize time and effort required of both industry and the NRC by providing for a single review and approval of the safety-related subject with subsequent referencing in licensing actions, rather than repetitive reviews of the same subject. The following criteria are used:

(1) The report deals with a specific safety-related subject regarding a nuclear power plant that requires a safety assessment by the NRC staff, such as component design, analytical models or techniques, or performance testing of components and/or systems that can be evaluated independently of any specific license application.
(2) The report is, or is expected to be, referenced in a number of license or standardized reference design approval applications.
(3) The report contains complete and detailed information on the specific subject presented. Conceptual or incomplete preliminary information will not be reviewed.
(4) NRC approval of the report will result in increased efficiency of the review process for applications that reference the report.

Licensing topical reports that present a new design or procedure not currently addressed in any license or standardized reference design approval application require special consideration. In support of such a report, the sponsoring organization must identify that potential applicants intend to reference the report before the NRC commits resources to perform the review.

When the NRC determines that a licensing topical report is acceptable for referencing, it will give the extent and the conditions for acceptance, if any, in a letter transmitting the results of the evaluation. Upon referencing the topical report in a licensing application, the licensee may be requesting that the topical report become part of a facility's licensing bases. This is clear when the topical report is incorporated by reference into the updated FSAR or when the topical is included in the list of methodologies listed in the technical specifications. Upon referencing an approved topical that is referenced in the updated FSAR or the technical specifications, the licensee is accepting the conditions imposed in the NRC's acceptance (i.e., the staff's safety evaluation, including any specified conditions, is an integral part of the "approved" version of the topical report). For the topicals incorporated by reference, the licensee may control the topical in accordance with the provisions of 10 CFR 50.59. Referencing of a topical report in the technical specifications may not include the ability of revising the topical in accordance with the revised 10 CFR 50.59 criterion for evaluating changes to methodologies. The staff and licensees should reach a mutual understanding for the change-control provisions when using topical reports in support of licensing actions (e.g., including a discussion of change-control mechanisms in the topical or NRC safety evaluation). A reference to a topical report in a licensing submittal without subsequent description of the methodology in the updated FSAR, incorporation of the topical by reference in the updated FSAR, or entry into another specific element of the licensing bases introduces confusion about the standing of the topical and any conditions that the staff included in its evaluation. If the desire is to incorporate the topical into the licensing bases, the staff and licensee should mutually agree on its importance and its placement. References to topicals may also be included in submittals as ancillary or non-licensing bases information provided to help the NRC during its review process.

6.3 – Regulatory Guides

Regulatory guides are issued to describe methods acceptable to the NRC staff for implementing specific parts of the NRC's regulations, to explain techniques used by the staff in evaluating specific problems or postulated accidents, and to provide guidance to applicants. Regulatory guides are not substitutes for regulations, and compliance with regulatory guides is not required. Regulatory guides are issued in draft form for public comment to involve the public in developing the regulatory positions. Draft regulatory guides have not received complete staff review; they therefore do not represent official NRC staff positions. Licensees often reference or make regulatory commitments to follow regulatory guides in order to facilitate the NRC review of an issue. The regulatory guides were used extensively during initial licensing and most recent FSARs include information regarding those regulatory guides that the licensee has committed to follow and those for which the licensee has taken an alternate approach. It is the licensee's commitment to follow the regulatory guide or inclusion of the information into the updated FSAR that incorporates it into the licensing bases. It is possible that some regulatory guides are incorporated by reference, or by other means get captured into a different part of the licensing bases.

6.4 - Industry Codes and Standards

Industry codes and standards document a consensus reached by the sponsoring organization that the code or standard provides an acceptable process and/or criteria to accomplish the task addressed by the code or standard. Some industry codes and standards are formally accepted by the NRC while others are not. Somewhat like topical reports, NRC acceptance of an industry code or standard is a matter of efficiency and predictability in terms of its incorporation into rules, or otherwise its application to multiple licensees. Licensees often reference or make regulatory commitments to follow particular industry codes and standards (or portions thereof) to facilitate the NRC review of an issue. The use of industry codes and standards was common during initial licensing. They may also be related to NRC regulatory guides. It is the licensee's commitment to follow the code or standard or inclusion of the information into a rule or the updated FSAR that incorporates it into the licensing bases.

6.5 - NRC Safety Evaluations (or Safety Evaluation Reports [SERs])

NRC safety evaluations provide the regulatory bases for NRC decisions in licensing actions such as amendments, exemptions and relief requests. Safety evaluation reports are generally used for more significant licensing actions such as initial operating licenses and renewed operating licenses. The distinction between an SE and SER is that the SER is issued as a NUREG series report.

The SEs and SERs are valuable in that they provide the bases for the staff's decisions. The staff should not attempt to establish licensing bases information in SEs or SERs. The staff can stress the importance of certain licensing bases information and can cite regulations, regulatory commitments, or other established licensing bases information in its safety evaluations. It is important that the licensees provide the licensing bases information so that there is no confusion following the licensing action and to avoid a perception of staff-imposed backfits (see 10 CFR 50.109). A useful application of the staff's SEs, by both licensees and the staff, can be in assessing what information is incorporated into mandated licensing bases documents. For example, in determining what information should be included in an FSAR update following a license amendment or response to a generic communication, licensees (and possibly the staff during related discussions, inspections or reviews) should consider the insights offered by the SE as part of the process described in 10 CFR 50.71(e) and related guidance documents such as NEI 98-03, Revision 1.

6.6 - NRC studies, reports, etc.

The NRC will occasionally perform studies, issue reports, or otherwise publish information about design features or operating practices at specific nuclear power plants. If these studies are performed outside of the licensing process and are not subsequently incorporated into the licensing bases by the affected licensee, the information is not licensing bases information. The staff should be cautious about subsequent uses of the reports or reliance on the information contained therein because there are no mechanisms for controlling or reporting changes to that information.

6.7 - Licensee Event Reports

Licensee event reports (LERs) are reports submitted by licensees in accordance with 10 CFR 50.73, "Licensee event report system." Most of the information within an LER should not be considered licensing bases information. The reports may contain detailed descriptions of SSCs or operating practices in order to describe an event or related corrective action. This information is generally considered to be non-licensing bases or ancillary information because the NRC has no expectation that, in the long-term, changes to that information are controlled or reported to the NRC (unless required by regulations other than 10 CFR 50.73). The corrective actions usually reported in LERs are under the auspices of the licensee's corrective action program and do not become part of the licensing bases by their inclusion in the LER. A general rule of thumb is that licensees will correct and update information for a period of time (around two years following submittal of the original LER) provided in LERs in order to support the NRC's evaluation of the event and the related risk and/or generic implications.

It is possible that a licensee may make a regulatory commitment within an LER. Such a regulatory commitment should be clearly defined and both licensee and staff should understand that such a statement will result in the inclusion of the commitment into the licensing bases and the licensee's commitment management program.

6.8 - Generic Communications

The various generic communications issued by the NRC are described in Regulatory Issue Summary 99-01, "Revisions to the Generic Communications Program," dated October 1, 1999.

Bulletins are used to address significant issues that also have great urgency. Bulletins are the only generic communications product that may be designated "urgent." Bulletins will be issued without public comment. A bulletin may request information or action or both and will require a response under oath or affirmation, in keeping with its urgent nature. Bulletins that request action will be reviewed in accordance with backfit requirements. Bulletins for reactor-related issues will always be subject to review by the Committee to Review Generic Requirements (CRGR), but not necessarily before they are issued.

Generic letters may request information or action or both. Generic letters are designated "routine." Therefore, the critical difference between bulletins and generic letters is that bulletins will be issued without public comment and generic letters will be published in the Federal Register for public comment. Generic letters that request action (versus only requesting information) will be reviewed in accordance with backfit requirements. Generic letters will typically not invoke oath or affirmation requirements unless the NRC has been unable to obtain needed information through other means. The staff will continue to provide the rationale for information requests, justifying the burden relative to the safety significance of the issue as described in the CRGR charter. Generic letters for reactor-related issues will always be subject to CRGR review before they are issued. Generic letters will not be issued without prior staff interaction with the industry and the public.

Generic communications are a tool for the NRC staff to request action by or information from licensees. They do not, in and of themselves, establish or revise the licensing bases for the regulated facilities. The generic letter or bulletin may, through its requested action or even its requested information, lead to a "reinterpretation" of a regulatory requirement that may have (from the licensee's perspective) the same effect as a revision to the licensing bases. Any such reinterpretations are, as mentioned above, subject to the backfit provisions of 10 CFR 50.109. It is, however, the licensee's response to a generic letter or bulletin that revises the licensing bases for an operating plant by including a regulatory commitment or revision to another licensing bases element.

Regulatory issue summaries are used to (1) document NRC endorsement of the resolution of issues addressed by industry-sponsored initiatives, (2) solicit voluntary licensee participation in staff-sponsored pilot programs, (3) inform licensees of opportunities for regulatory relief, (4) announce staff technical or policy positions not previously communicated to the industry or not broadly understood, and (5) address all matters previously reserved for administrative letters. CRGR will be given the opportunity to review all regulatory issue summaries for reactor-related issues before they are issued.

Information notices are used to inform the nuclear industry of significant, recently identified, operating experience. Information notices will not convey or imply new requirements or new interpretations, and will not request information or actions.

NRC publishes a Headquarters Daily Report to disseminate information to NRC regional offices. The contents of these reports vary, but can include information on licensee events, licensee organizational changes, and staff assessment activities. The staff has found that the Headquarters Daily Report is an effective tool for sending information to licensees and the public regarding potential generic issues that do not warrant a generic communication. The staff also publishes a Headquarters Daily Report when it initiates development of a generic communication with the expectation that interested parties can comment on the proposed generic communication early in the development process. The Headquarters Daily Report is available on the NRC web site.

6.9 - Inspection Reports

NRC inspectors may provide information in an inspection report to explain how a licensee complies with a regulation or other element of a facility's licensing bases. The inclusion of information within an NRC inspection report does not affect the licensing bases of the subject facility. The staff can stress the importance of certain licensing bases information and can cite regulations, regulatory commitments, or other established licensing bases information in its inspection reports. Although the report may provide details of how a licensee has implemented the licensing bases or provide other useful information, any details beyond the existing licensing bases should be considered non-licensing bases or ancillary information. If it is appropriate for the licensing bases to be revised as a result of an inspection activity, the inspectors (regional or headquarters) should refer the matter to NRR/DLPM for action. It is important that the licensees provide any revised licensing bases information to NRR in order to ensure consistency and avoid a perception of staff-imposed backfits (see 10 CFR 50.109).

6.10 - Responses to Notices of Violations

Licensees are required to respond to some Notices of Violations (NOVs). The information within a response to an NOV should not generally be considered licensing bases information. The responses may contain detailed descriptions of SSCs or operating practices in order to describe a violation or related corrective action. This information is generally considered to be non-licensing bases or ancillary information because the NRC has no expectation that, in the long-term, changes to that information are controlled or reported to the NRC. The corrective actions usually reported in NOV responses are under the auspices of the licensee's corrective action program and do not become part of the licensing bases by their inclusion in the response. A general rule of thumb is that licensees will correct and update information for a period of time (around two years following the response or upon closure of the violation in an inspection report) provided in an NOV response.

It is possible that a licensee may make a regulatory commitment within a response to an NOV. Such a regulatory commitment should be clearly defined and both licensee and staff should understand that such a statement will result in the inclusion of the commitment into the licensing bases and the licensee's commitment management program.

6.11 - Systematic Evaluation Program (SEP)

Generic Letter 95-04, "Final Disposition of the Systematic Evaluation Program," documented the final disposition of the 27 lessons-learned issues found in the Systematic Evaluation Program (SEP). The program is discussed here because (1) the SEP did result in some changes to the licensing bases for operating reactors (i.e., some issues that were resolved led to a revision to one or more elements of the licensing bases) and (2) the reports generated by the SEP can be a valuable reference regarding the licensing bases for older plants.

In 1977, the NRC staff initiated the SEP to review the designs of older operating nuclear power plants, i.e., plants licensed before 1975 when the Standard Review Plan (SRP) was issued. In Phase I, the NRC staff identified 137 issues for which the regulatory requirements had changed, and which warranted an evaluation. In Phase II, the NRC staff compared the designs of 10 SEP plants to the SRP issued in 1975. The NRC staff found that 27 of the original 137 issues required some corrective action at one or more of the 10 plants examined in the SEP. The NRC staff also concluded that corrective actions for these 27 issues could benefit safety at older operating plants not in the group of 10 plants examined in the SEP (non-SEP plants). Therefore, the NRC staff concluded that these 27 issues should be considered at the non-SEP plants to determine whether an adequate level of safety existed at these plants.

To determine what actions might be appropriate for the non-SEP plants, the NRC staff determined whether each SEP issue had been resolved by a particular licensee, needed to be resolved, or was addressed by other regulatory programs and activities, and placed the SEP issues in four categories. This information was sent to the Commission in SECY-90-343, dated October 4, 1990, as follows:

(1) Completely resolved (4)
(2) Low safety significance requiring no further regulatory action (1)
(3) Unresolved but covered by existing regulatory programs (19)
(4) Unresolved; existing regulatory program has not yet been identified (3)

Further evaluation by the NRC staff as part of the generic safety issues program (NUREG-0933, "A Prioritization of Generic Safety Issues") led to some adjustments among the categories after SECY-90-343 was issued. The final categorizations follow:

(1) Completely resolved (4)
(2) Low safety significance requiring no further regulatory action (2)
(3) Unresolved but covered by existing regulatory programs (20)
(4) Unresolved; existing regulatory program has not yet been identified (1)

The NRC staff determined that the 21 issues remaining in categories 3 and 4 did not require immediate action to protect public health and safety, and incorporated them into the established NRC regulatory process for determining the safety importance of generic safety issues. The 20 issues in category 3 are covered by existing regulatory programs described in NUREG-0933. The NRC staff incorporated the category 4 issue (SEP Issue 6.1, "Pipe Break Effects on Systems and Components") into the generic issues program (Generic Issue 156.6.1).

Following the generic letter, the NRC staff no longer tracked SEP issues separately because each original SEP issue was either resolved, did not need to be resolved, or was incorporated into the generic issues program.

6.12 - Standard Review Plan

The standard review plan (SRP) was prepared for the guidance of staff in performing safety reviews of applications for construction permits and operating licenses. The principal purpose of the SRP is to assure the quality and uniformity of staff reviews and to present a well-defined base from which to evaluate proposed changes in the scope and requirements of reviews. It was also a purpose of the SRP to make information about regulatory matters widely available and to improve communication and understanding of the staff review process by interested members of the public and the nuclear power industry.

The technical bases for some sections of the SRP are provided in Branch Technical Positions or Appendices which are included in the SRP. These documents typically set forth the solutions and approaches determined to be acceptable by the staff in dealing with a specific safety problem or safety-related design area. Like Regulatory Guides, the Branch Technical Positions and Appendices represent solutions and approaches that are acceptable to the staff, but they are not required as the only solution and approaches. The creation of the Branch Technical Position was intended to increase staff and licensee efficiencies by providing a common framework or reference for particular issues.

In 1981, the standard review plan was revised in its entirety and published as NUREG-0800. Since that time, the updating of the SRP has been limited to several specific issues. This approach has resulted in the SRP being outdated in some areas and relatively up-to-date in other areas. The SRP may remain a useful reference but the staff should also use precedent reviews contained in safety evaluations or other documents containing more recent technical positions.

The acceptance criteria in the SRP are also being used in the guidance for the recent changes to 10 CFR 50.59. The criteria are being used to aid in assessments of plant changes to determine if the changes have “more than a minimal” increase in the consequences of an accident previously evaluated. See RG 1.187 and NEI 96-07, Revision 1 for additional information on how the acceptance standards in the SRP are used to determine if changes in a facility require prior NRC review and approval.

ATTACHMENT 1

Office Instruction LIC-100, "Control of Licensing Bases for Operating Reactors" - Summary Table

Quick Reference Aid	Obligations							Mandated Licensing Bases Documents									Regulatory Commitments
	Regulations				Operating License & Technical Specifications			UFSAR		Tech Spec Bases Section	QA Program	Emergency Preparedness Program	Security Plan	Fire Protection Program	ODCM	COLR & PTLR	
	General Regulations	50.55a	50.46	License Transfers	License	Technical Specifications	Orders	UFSAR (including design basis	TRM								
Regulatory Bases	10 CFR	50.55a	50.46 & Appendix K	50.80	10 CFR	50.36	2.202	50.34	License Amendment	50.36 & Admin Controls in Tech Specs	50.34(b), 50.54(a), Appendix B	50.34(b), 50.47, 50.54(q), Appendix E	73.55 and 50.54(p)	GDC 3, 50.48, Appendix R	TS Admin Controls Section	TS Admin Controls Section	n/a (54.3 definition of CLB)
Location of Information	10 CFR	ISI/IST Programs	FSAR / topical reports	various	License (including conditions)	Technical Specifications	Order	UFSAR	TRM (as extension of UFSAR)	TS Bases Section	Quality Assurance program	Emergency Plan	Security Plan	Fire protection Program	ODCM	COLR & PTLR	various docketed
Nonconformances or Unplanned Changes	GL 91-18 & C/A Program	Verbal or Interim Relief	C/A program - submit plan to NRC if > 50F	n/a	GL 91-18 & C/A Program	NOED & emergency - exigent changes	GL 91-18 & C/A Program	91-18 & C/A Program	91-18 & C/A Program	91-18 & C/A Program	91-18 & C/A Program	91-18 & C/A Program	As directed by Secuurity Plan	As directed by Fire Protection Plogram	C/A Program	C/A Program	91-18 & C/A Program
Planned or Routine Changes	Exemptions (50.12)	Relief Requests	NRR review of evaluation model	50.80 & 50.90 applications	50.90	50.90	50.90 or 2.202	50.59	50.59	50.59 (per TS Admin Control)	50.54(a)	50.54(q)	50.54(p), 50.90 for changes requiring prior approval	50.12, standard license condition	Per TS Admin Controls Program	Per TS Admin Controls Program	NEI 99-04 (or similar)
Reporting	no specific	50.55a (*including* possible prior review)	50.46(a)(3)	prior approval	license specific and prior approval	license specific and prior approval	Order specific and prior approval	50.71 & 50.59 or prior approval	50.71 & 50.59 or prior approval	similar to 50.71 (per TS or admin controls) or prior approval	50.71 or prior approval	50.54(q) (30 days) or prior approval	50.54(p) (2 months) or *prior* approval	FSAR(50.71) or on site *or prior* approval	Per TS Admin Controls Program	Per TS Admin Controls Program	NEI 99-04 (or similar)
Verification and Monitoring	Insp Program & Licensing Process	Insp Program & Licensing Process	Licensing Reviews	n/a	Insp Program & Licensing Process	Insp Program & *Licensing* Process	Insp Program & *Licensing* Process	Insp Program & *some* NRR	Insp Program & *some* NRR	Insp Program & some NRR	Insp Prog & NRR Reviews	Insp Prog & NRR Reviews	Insp Prog & NRR Reviews	Insp Prog & NRR Reviews	Insp Prog & NRR Reviews	Insp Prog & NRR Reviews	NRR periodic assessments (to *be developed)*
Enforcement	Enf Manual	Enf Manual	Enf Manual	Enf Manual	Enf Manual	Enf Manual	*Enf Manual*	*Enf Manual*	*Enf Manual*	Enf Manual	Enf Manual	Enf Manual	Enf Manual	Enf Manual	Enf Manual	Enf Manual	Enf Manual (NOD)
Public Involvement	Public Record	Public Record	Public Record	Hearing Rights	Hearing Rights	Hearing Rights	Hearing Rights	Public Record (see License for changes needing *NRC* approval)	Public *Record* (see License for changes *needing NRC* approval)	Public *Record* (see License for changes *needing NRC* approval)	Public Record	Public Record	Limited Public Record (see License for changes needing NRC approval)	Per update process and exemption process	Public Record	Public Record	Public Record
Available Guidance Office Instructions Issued or Planned	LIC-103	OL 808 LIC-102		License Transfer SRP LIC-107	OL 803 LIC-101	OL 803 LIC-101	LIC-106	RG 1.181 RG 1.186 RG 1.187					OL 801 LIC-104		GL 89-01	GL 89-16 GL 96-03	OL 900 *LIC-105*