June 22, 1982

SECY-82-258

ADJUDICATORY ISSUE

~~(Affirmation)~~ NOTATION

For: The Commissioners

From: Martin G. Malsch, Deputy General Counsel

Forrest J. Remick, Director, OPE

Subject: REVIEW OF DIRECTOR'S DECISION ON 2.206 PETITION (ROCHESTER GAS AND ELECTRIC CORPORATION)

Facility: R. E. Ginna Nuclear Power Plant

Review Time Expires: July 2, 1982

Discussion: By petition dated March 11, 1982 the Sierra Club requested the Director, NRR to initiate a full review of the ability of RG&E to safely operate the Ginna reactor in light of the January 25 steam generator tube break accident. The Sierra Club set forth sixteen specific areas that should be reviewed, stating that the requested review should be made a part of the review then in progress by staff. The Sierra Club further requested that, pending completion of this review, the operating license for Ginna be suspended, or, in the alternative, that restart not be permitted.

The Director acknowledged receipt of this petition by letter dated March 31, 1982. In that letter the Director noted that eleven of the items listed

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in the Sierra Club's petition had already been proposed to be incorporated into the staff's Safety Evaluation Report (SER). The Director also noted that the SER would issue prior to restart.

The Director issued his decision on May 22, 1982. The Director granted the Sierra Club's request that the specific areas detailed in the petition be considered in the ongoing staff safety review. All but parts of four items were discussed in the SER (NUREG-0916). Those four items were discussed in the Director's decision itself. 1/

As to the request that the operating license be suspended pending a completion of the safety review, the Director noted that a formal order had been unnecessary because the licensee had agreed to delay restart until it received staff approval.

Ex.
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1/ These four items involved (1) whether a reliable method exists for removing decay heat by means of the secondary system; (2) the problems associated with use of the PORV for coolant discharge during "feed and bleed" cooling; (3) worker exposure during repairs; and (4) whether the newest Westinghouse steam generator design will ameliorate steam generator problems.

Ex.
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2/ This letter, which critiqued the Director's Decision, was written "to encourage the Commission" to review the Director's Decision.

Recommendation:

Ex. 5

Martin G. Malsch
Deputy General Counsel

Forrest J. Remick
Director, OPE

Enclosures:
(1) Sierra Club's petition
(2) Director's Decision
(3) NUREG-0916
(4) Sierra Club's letter 6/10
(5) Memo

Commissioners' comments should be provided directly to the Office of the Secretary by c.o.b. Friday, July 2, 1982.

Commission Staff Office comments, if any, should be submitted to the Commissioners NLT Friday, June 25, with an information copy to the Office of the Secretary. If the paper is of such a nature that it requires additional time for analytical review and comment, the Commissioners and the Secretariat should be apprised of when comments may be expected.

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Attachment 1 Rel

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

In the Matter of Rochester Gas and Electric Corporation R.E. Ginna Nuclear Power Plant	))))))	Docket No. 50-244

SIERRA CLUB PETITION

FOR ORDER TO SHOW CAUSE

INTRODUCTION

This petition is brought before the Office of Nuclear Reactor Regulation by the Sierra Club. Pursuant to 10 CFR 2.206, 50.54, 50.100 and 50.109, and for reasons set forth below, the Sierra Club requests that Rochester Gas and Electric Company be required to show cause, as provided in 10 CFR 2.202, why the operating license for the Ginna nuclear reactor in Ontario, New York, should not be suspended, or in the alternative, why permission to re-start the reactor should not be withheld, until such time as essential actions have been taken by the licensee and the Commission to assure the protection of public health and safety. The necessity for such actions arises from the accident on January 25, 1982, which was initiated by a steam generator tube break and which triggered a site emergency.

In requesting this action, the Sierra Club wishes to stress our concern regarding the potentially serious safety implications of the Ginna accident, not only to our 500 members living in Rochester, but also to the general public. Further, as a national environmental organization with approximately 225,000 members across the country and 18,000 members in New York State, we are concerned about the implications of the Ginna accident for the safe operation of other pressurized water reactors in New York and across the country.

Given the clear safety implications of both under- and over-pressurization which can arise subsequent to a steam generator tube break, the Sierra Club concurs with the November 24, 1981, "Information Report--Steam Generator Tube Experience" by NRC staff which states:

> These tubes, like many interface components, affect both [primary and secondary] systems, and their failure is an operational as well as a potential safety concern. Therefore, the steam generator must be viewed as part of the total system in which it operates. Thus, maintaining the integrity of the tubes requires a systems approach that should encompass mechanical, structural, material, and chemical considerations. (page 35, emphasis added)

RELIEF REQUESTED

The Sierra Club requests that the Director of Nuclear Reactor Regulation initiate a full review by staff of matters pertaining to the ability of the licensee to safely operate the reactor so as to protect public health and safety, in light of the January 25th accident. Such review should be made part of the review now in progress by staff and should include, but need not be limited to, the specific areas detailed below. Pending completion of this review by the staff, the Operating License for Ginna should be suspended, or in the alternative, re-start of the reactor should not be permitted.

1. The cause of the tube break initiating the January 25, 1982, accident should be thoroughly explained and corrective action taken to prevent such breaks in the future. The mechanical damage arising from loose pieces of metal should be studied in the context of the generic corrosion problems at Ginna. Specifically, corrosion arising from AVT (all volatile treatment) control of secondary water chemistry should be addressed in relation to denting of tubes, stress

corrosion, and intergranular attack. This should include corrosion in the feedwater system and corrosive impurities introduced by condenser leaks.

2. The adequacy of the steam generator tube testing program should be evaluated and a determination made regarding the following issues:

a. Is the routine multi-frequency eddy current testing method being employed at Ginna the best available given current state-of-the-art? If not, what justification is there for not employing the best available technology, in light of chronic tube degredation problems at Ginna and at other PWR's and the existence of techniques such as fiber optic examination?

Is the frequency of required testing of tubes sufficient to prevent future tube rupture or other serious break?

c. Does the current testing program, which only tests a sample of tubes and which does not test their full length, provide sufficient information to prevent tube failure?

3. The technical specifications defining the extent of allowable tube degredation for steam generator tube rejections should be reviewed in light of the Ginna accident to determine whether they are sufficiently stringent to prevent a tube break.

4. The increased risk of steam generator tube breaks/leaks, if RG&E operates the reactor without having proceeded with the preventative sleeving program originally scheduled for the Spring 1982, refueling outage, should be assessed and a determination made as to whether the original schedule should be adhered to.

5. The safety implications of current and proposed plugging and sleeving of steam generator tubes and of further repairs such as insertion of stabilizing cables should be examined in order to assess additional stress, such as from changes in fluid dynamics, which may

be induced in tubes remaining in use.

6. An evaluation should be completed to determine the safety implications of operator action currently required to re-establish the instrument air system and to open the PORV manually.

7. The safety implications of the failure of the PORV to close should be assessed in light of the problems which developed during the Ginna accident, particularly with regard to the creation of a steam bubble in the reactor vessel as a result of depressurization. The potential for uncovering the core, due to a steam bubble in the reactor vessel or elsewhere in the primary system should be addressed. A determination should be made as to whether safety functions performed by the PORV require that it be designated as safety grade and be required to meet all NRC regulations applicable to such safety grade designation, in order to assure safe operation of the reactor.

8. A determination should be made, given the demonstrated unreliability of the PORV, as to whether a reliable method exists for removing decay heat by means of the secondary system, without providing, at the very minimum, one pathway for removing decay heat which consists of safety grade equipment. Such determination should also include an assessment of the reliability of essential auxiliary support systems such as instrument air, and should consider the consequences of loss of off-site power to determine whether General Design Criteria #17 of 10 CFR Part 50 Appendix A is met.

9. A determination should be made as to whether the emergency operator procedures set forth in "Westinghouse Emergency Operator Guidelines for Steam Generator Tube Rupture Events" are adequate to protect the public health and safety. Operator delay, or apparent hesitancy, in terminating the HPI (high pressure injection) is of particular concern in relation to the risk of over-pressurization

of the reactor pressure vessel as reported in the Speis memorandum (see infra #11) and to the increased reliance on proper functioning of steam generator safety valves. Further, the Ginna emergency procedures should be conformed to the Westinghouse guidelines.

10. The conditions under which the reactor vessel can become over-pressurized in the course of operator action to control an accident should be clearly specified and a determination made as to whether an automatic response system would decrease the chance of over-pressurization problems from developing and whether the installation of such a system at Ginna is an action that "will provide substantial, additional protection which is required for the public health and safety...." as provided in 10 CFR 50.109.

11. The concerns raised in the Speis memorandum (Themis Speis to Roger Mattson, "Preliminary Evaluation of Operator Action for Ginna SG Tube Rupture Event" dated January 28, 1982, see infra Attachment E) regarding problems and potential problems in cooling the reactor following the tube break should be addressed; a determination made as to their safety significance; and necessary corrective action taken. These include the following problems:

a. the apparent stratification in the B steam generator and its effect on slowing depressurization of the faulted steam generator;

b. the consequence of an additional coolant system failure, including a leak in the A steam generator or "a secondary side safety/relief valve" sticking open;

c. the necessity to remove decay heat from the A steam generator by steaming to the atmosphere due to improper functioning of the condensor;

d. the problems associated with the use of the PORV for coolant discharge during "feed and bleed" cooling.

12. A determination should be made as to the extent to which failure to implement the TMI Action Plan requirement for instrumentation to allow direct measurement of the water level in the reactor vessel contributed to operator problems in determining proper timing for operating the ECCS pumps and in determining the size of the steam bubble.

13. A full investigation should be made to determine the state of embrittlement of the Ginna reactor pressure vessel to determine the likelihood that over-pressurization will lead to vessel rupture as a consequence of pressurized thermal shock.

14. The NRC should determine whether the reactor can operate safely without replacement of the steam generator and associated parts of the nuclear steam supply system and whether the newest Westinghouse steam generator design will ameliorate the problems, given the recent problems which have developed with this design at McGuire and at European reactors.

15. The total projected worker exposure should be calculated in advance of NRC approval of RG&E's repairs and a specific plan developed to keep worker exposure as low as reasonably achievable (ALARA). This should include a determination as to whether time should be allowed for radioactive decay, particularly of Cobalt 58, in the steam generator prior to repairs, in order to prevent unnecessary worker exposure and still allow all necessary repairs to be made.

16. An overall safety assessment should be performed before the reactor is allowed to re-start in order that the combined risk of potential failure modes can be determined, in relation to the protection of public health and safety. At a minimum such an assessment should

address the following:

a. the degredation of the Ginna steam generators, including the plugging, sleeving and other repairs required to date and planned;

b. the on-going contribution to tube degredation of corrosion arising from AVT control, from condenser leakage, and from the feedwater system (as opposed to the suspected damage from loose pieces of metal in the B steam generator);

c. the lack of a safety grade pathway in the secondary system to remove decay heat;

d. the chance that operator error will lead to over- or under-pressurization of the reactor vessel;

e. the state of reactor vessel embrittlement.

The facts which constitute the basis for our request are set forth in Attachments A, B, C, D and E.

We respectfully request that a decision on our petition be rendered forthwith.

On behalf of the Sierra Club,

Respectfully submitted by,

Ruth N. Caplan

Ruth N. Caplan, Chair
Sierra Club National Energy Committee

278 Washington Blvd.
Oswego, New York 13126

315-343-2412

I hereby affirm that the facts alleged herein are true and correct to the best of my knowledge and belief.

Ruth N. Caplan

Ruth N. Caplan

DATED: March 11, 1982

AFFIDAVIT OF BEATRICE ANDERSON

1. My name is Beatrice Andersen. I live at 12 Spinet Drive, Rochester, New York 14625, which is about 20 miles from the Ginna reactor owned by Rochester Gas and Electric.

2. I am a member of the Sierra Club and I chair the Rochester Group of the Sierra Club which has 500 members in the Rochester area.

3. On behalf of myself and the Rochester Group, I authorize the Sierra Club to represent my interests in the request for show cause action before the U.S. Nuclear Regulatory Commission. These interests include the potential danger to my health and safety if the Ginna reactor is allowed to restart prior to such actions as are called for in the Sierra Club show cause request.

Beatrice Andersen

Sworn and subscribed to before me this 23rd day of February, 1982.

Edwin R. Jeffries Jr.

Notary Public

EDWIN R. JEFFRIES JR.
Notary Public in the State of New York
MONROE COUNTY, NEW YORK
Commission Expires March 30, 19__

My commission expires __________.

ATTACHMENT A. FACTUAL BASIS FOR SHOW CAUSE PETITION

1. On January 25, 1982, a steam generator tube rupture at the Ginna nuclear plant in Ontario, New York, occurred. The rupture occurred in a tube which was last inspected in May, 1981, at which time the tube showed less than 20% ~~washing~~ of the tube wall, according to "Weekly Information Report, February 18, 1982, from T.A. Rehn, Assistant for Operations Office of the EDO to the Commissioners", included herein as Attachment B.

2. It is our understanding that RG&E has not yet been able to provide a satisfactory explanation for the rupture of the steam generator tube. Upon information and belief, a clear relationship has not been established between loose pieces of metal discovered in the steam generator, the damaged peripheral tubes, and the ruptured tube. An alternate explanation linking the rupture to stress corrosion has been advanced by RG&E. (See Rehm memo, page 2 of Enclosure B)

3. Upon information and belief, the Ginna tube testing program has been based on multi-frequency eddy current testing at the time of refueling. Such testing has included only a sample of tubes and only part of the tube length has been examined. According to Nuclear Safety, "most tubes were tested to the first support plate, some to the sixth support plate, and a few over the U-bend." (Nuclear Safety, V. 22, N. 5, Sept.-Oct., 1981. Included infra as Attachment C.)

4. Upon information and belief, the "Quality Assurance Manual, Ginna Station--Inservice Inspection Program for the 1980-1989 Interval" allows the tube inspection interval to be extended to once every 40 months under certain conditions. Section 2.5 of this document states:

> The inservice inspection intervals for the examination of steam generator tubes shall not be more than 24 months. However, if over a nominal two year period (e.g., two normal fuel cycles) at least two examinations of the separate legs result in less than 10% of the tubes with detectable wall penetration (> than 20%) and no significant (> than 10%) further penetration of tubes with previous indications, the inspection interval of the individual legs may be extended to once every 40 months. (page 5 of 22)

5. Upon information and belief, RG&E reported to the NRC staff on February 10, 1982, that tests after the accident did not reveal serious problems with the steam generator tubes which would prevent RG&E from re-starting the reactor. Yet After fiber optic examination was required by staff, serious problems were found in tubes previously plugged. John Maier, RG&E Vice-president for Electric and Steam Generation, commented to the press the next day: "The pictures are very dramatic.... It looks like somebody went in with a hacksaw. Some of the tubes show severe denting and external degredation." (AP quoted in Palladium-Times, Feb. 12, 1982) Further examination revealed two pieces of metal weighing "'a couple of pounds'...with one of them as large as 6.5 x 4 inches and seven-sixteenths inches thick." (Nucleonics Week, Feb. 18, 1982) As reported in Nucleonics Week, Feb. 25, 1872, one RG&E source stated: "'Some are corroded, some are imploded, some are just sheared.'"

6. Upon information and belief, RG&E was planning an extensive sleeving program to remedy corrosion problems regarding the steam generator tubes. In a letter from John Maier to Dennis Crutchfield, January 15, 1982, RG&E requested permission to "delete the 25 sleeve limitation" so that more sleeves could be installed during each steam generator inspection. (See infra, Attachment D.)

7. As recently as September 21, 1981, Ginna was not listed as one of the 11 units with the most serious steam generator problems (New York Times, Sept. 21, 1981, B-10). It is our opinion that this fact emphasizes the unpredictable nature of the rupture and reinforces the need for much more stringent test procedures.

8. Upon information and belief, the introduction of AVT control of secondary water chemistry at Ginna has led to problems of intergranular attack and tube corrosion, requiring the plugging of steam generator tubes. (Nuclear Safety, Ibid.)

9. As indicated in the Point Beach proceedings, AVT control does not function to precipitate out solid impurities that leak into the generator and does not prevent build-up of hardness scale on the heat transfer surfaces. Both conditions degrade steam generator tubes. (Docket 6630, ER-10, Exhibit 16E at 14-15)

10. As observed by NRC staff, "denting" of steam generator tubes occurred in several PWR facilities, including Turkey Point, Units 3 and 4, and Surry, Units 1 and 2, after 4 to 14 months of operation, following the conversion from a sodium phophate treatment to AVT chemistry for the steam generator secondary coolant. ("Information Report--Steam Generator Tube Experience, November 24, 1981, SECY 81-664," Appendix B, page 3.) We note hte report's observation that: "Tube denting is most severe in the rigid regions or so-called 'hard spots' in the tube support plates. These hard spots are located...around the peripheral locations of the support plate where the plate is wedged to the wrapper and shell." (Ibid., page 3) Upon information and belief, the staff has already requested that RG&E have Westinghouse prepare a report regarding this matter.

11. The NRC "Information Report--Steam Generator Tube Experience" concludes: "copper alloys should be eliminated from all areas of the condensate/feedwater/steam condensation cycle. Substantial evidence exists that copper oxides in the steam generators are an important catalyst in accelerating the rate of corrosion processes within the steam generators." (Ibid., p. 42)

12. Condenser leakage is also relevant to the action at hand. Staff states: "With the exception of a few reactors which are sited where no acid producing species exists in the condenser cooling water, all currently operating plants are susceptible to denting, if sufficient condenser leakage occurs. Because copper oxide has been demonstrated to be a catalyst, those plants with copper in their secondary cycles are even more susceptible." (Ibid., Appendix A, page 6)

13. Steam generator problems are not automatically solved by installing new steam generators as evidenced by the problems faced by Prairie Island 2 and by North Anna 1. Brookhaven National Laboratory commented

last year as follows:

> It seems ironical that Prairie Island 2, which has no copper in the system, stainless steel condensers, and meticulous monitoring of water chemistry, should be the one unit to have suffered from this particular phenomenon (of tube corrosion): the Prairie Island Units have to date been a shining example of what we thought was the proper way to avoid corrosion problems.
> (Docket 6630, CE-20, Exhibit 40, p.3)

Such experiences make it all the more imperative to have a stringent testing schedule for tubes and strict standards for removing tubes from service.

14. Upon information and belief, the sequence of events during the January 25 accident clearly indicate the interdependency of the nuclear steam supply system and the reactor safety system. Reactor trip in response to the tube break initiated containment isolation which resulted in loss of instrument air. This required operator action to open the PORV manually, when the valve was required to relieve over-pressurization. The reactor vessel became under-pressurized when the POR stuck open and the block valve had to be closed. Lowered pressure produced a steam bubble in the top of the reactor vessel when water flashed to steam. A second drop in pressure about 30 minutes later again led to water in the reactor vessel flashing to steam. (Source: "Preliminary Evaluation of Operator Actions for Ginna SG Tube Rupture Event" by Themis Speis. See infra Attachment E.)

15. Upon information and belief, the Speis memo also indicates that over-pressurization of the reactor vessel was of concern during the sequence of events during which operators tried to stabilize the reactor. First, charging pumps were restarted before the B steam generator was isolated, leading to a build-up of reactor pressure. Second, the SI pump was restarted without apparent need to do so, which has elicited concern regarding operator hesitance to terminate HPI and the consequence for pressurized thermal shock.

16. According to the "Information Report--Steam Generator Tube Experience," the total man-rems exposure can be quite significant. The report states: "Where major repair or replacement efforts are required, dose expenditures may range from 2000 to 3500 man-rems." (Ibid, page 5.) The largest dosage reported results from steam generator repair at San Onofre Unit 1, where 3493 man-rems exposure is reported for the 273-day outage during 1980-1981. (Ibid, Table 6) This is more than the 1759 man-rems for steam generator replacement at Surry, Unit 1 or the 2140 man-rems for Surry, Unit 2 replacement. (Ibid., Appendix B, page 13 and Table 6) It is our belief that these dose levels point to the need to evaluate total man-rems exposure in determining the best course of action to be followed at Ginna.

Attachment 2

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

May 22, 1982

Docket No. 50-24
DD-82-03

Ms. Ruth Caplan, Chair
Sierra Club National Energy Committee
278 Washington Boulevard
Oswego, New York 13126

Dear Ms. Caplan:

This is in response to your petition dated March 11, 1982, as revised by your letter dated March 25, 1982, requesting consideration and resolution of a number of issues before the R. E. Ginna Nuclear Power Plant resumes operation. By letter dated March 31, 1982 we acknowledged receipt of your letter and informed you that your request was being considered under the provisions of 10 CFR 2.206 of the Commission's regulations. At that time we informed you that items 1, 2, 3, 4, 5, 6, 9, 13, 14, 15 and 16 would be considered for incorporation into the staff's Safety Evaluation Report (SER), NUREG-0916 prior to restart of the Ginna plant.

This office has determined, for the reasons stated in the SER, to allow Rochester Gas and Electric Corporation to resume operation of the Ginna plant. With the exception of items 8, 11d, 15 and part of item 14, all the issues you have raised are addressed in NUREG-0916 (enclosed). The remaining items are specifically discussed in the Director's Decision enclosed with this letter.

A copy of this determination will be placed in the Commission's Public Document Room at 1717 H Street, N. W., Washington, D. C. 20555 and at the Rochester Public Library, 115 South Avenue, Rochester, New York 14604.

The decision will also be filed with the Secretary of the Commission for its review in accordance with 10 CFR 2.206(c) of the Commission's regulations. As provided for by this regulation, the decision will constitute the final action of the Commission twenty-five (25) days after the date of issuance of the decision unless the Commission, on its own motion, institutes a review of the decision within that time.

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A copy of the Notice of Issuance of the Director's Decision, which is being filed with the Office of the Federal Register for publication, is also enclosed.

Sincerely,

Harold R. Denton

Harold R. Denton, Director
Office of Nuclear Reactor Regulation

Enclosures:
1. Director's Decision
2. Ginna Restart Safety Evaluation Report (NUREG-0916)
3. Notice of Issuance

cc w/enclosures:
See next page

nlean

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

OFFICE OF NUCLEAR REACTOR REGULATION
HAROLD R. DENTON, DIRECTOR

In the Matter of	)
	)
ROCHESTER GAS AND ELECTRIC CORPORATION	) Docket No. 50-244
	) (10 CFR 2.206)
	)
R. E. Ginna Nuclear Power Plant	)

DIRECTOR'S DECISION UNDER 10 CFR SECTION 2.206

By a petition dated March 11, 1982 Ms. Ruth N. Caplan, Chairman, Sierra Club National Committee, requested the Nuclear Regulatory Commission's Office of Nuclear Reactor Regulation require Rochester Gas and Electric Corporation (the licensee) to show cause why the operating license for the Ginna plant should not be suspended, or in alternative, why permission to restart the reactor should not be with-held, until such time as essential actions have been taken by the licensee and the Commission to assure the protection of public health and safety. This request has been considered under 10 CFR Section 2.206 of the Commission's regulations.

The petitioner requests that the Director of Regulation initiate a review of matters pertaining to the ability of the licensee to safely operate the Ginna plant so as to protect public health and safety in light of the January 25, 1982, steam generator tube rupture at the Ginna plant. The petitioner further requested that this review be incorporated into the review which was in progress by the staff at that time and that it should include, but need not be limited to several specific areas discussed in the petition. Pending completion of this review, the petitioner requested that the operating license for Ginna be suspended, or in the alternative, restart of the reactor should not be permitted.

I have reviewed the information submitted by Ms. Caplan and other relevant information bearing on the issues addressed in the petition.

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The petitioner's request that the ongoing staff safety review include and consider the specific areas detailed in the petition is granted. Many of the specific issues are addressed in the staff's Safety Evaluation Report (NUREG-0916). A reference to NUREG-0916 or a discussion of each item follows.

Petitioner's Assertion and Request

1. The cause of the tube break initiating the January 25, 1982, accident should be throughly explained and corrective action taken to prevent such breaks in the future. The mechanical damage arising from loose pieces of metal should be studied in the context of the generic corrosion problems at Ginna. Specifically, corrosion arising from AVT (all volatile treatment) control of secondary water chemistry should be addressed in relation to denting of tubes, stress corrosion, and intergranular attack. This should include corrosion in the feed-water system and corrosive impurities introduced by condenser leaks.

Response:

These issues are discussed in Sections 5.2, 5.3 and 5.4 of NUREG-0916.

Petitioner's Assertion and Request

2. The adequacy of the steam generator tube testing program should be evaluated and a determination made regarding the following issues:
   a. Is the routine multi-frequency eddy current testing method being employed at Ginna the best available given current state-of-the-art? If not, what justification is there for not employing the best available technology, in light of chronic tube degradation problems at Ginna and at other PWR's and the existence of techniques such as fiber optic examination?
   b. Is the frequency of required testing of tubes sufficient to prevent future tube rupture or other serious break?
   c. Does the current testing program, which only tests a sample of tubes and which does not test their full length, provide sufficient information to prevent tube failure?
3. The technical specifications defining the extent of allowable tube degradation for steam generator tube rejections should be reviewed in light of the Ginna accident to determine whether they are sufficiently stringent to prevent a tube break.
4. The increased risk of steam generator tube breaks/leaks, if RG&E operates the reactor without having proceeded with the preventative sleeving program originally scheduled for the Spring, 1982, refueling outage, should be assessed and a determination made as to whether the original schedule should be adhered to.

Response:

These issues are addressed in Section 5.2.4 of NUREG-0916.

Petitioner's Assertion and Request

5. The safety implications of current and propos... plugging and sleeving of steam generator tubes and of further repairs such as insertion of stabilizing cables should be examined in order to assess additional stress, such as from changes in fluid dynamics, which may be induced in tubes remaining in use.

Response:

5.5.8

These issues are addressed in Section 5.5.7 of NUREG-0916.

Petitioner's Assertion and Request

6. An evaluation should be completed to determine the safety implications of operator action currently required to re-establish the instrument air system and to open the PORV manually.

Response:

This issue is addressed in Section 4.2.3 of NUREG-0916.

Petitioner's Assertion and Request

7. The safety implications of the failure of the PORV to close should be assessed in light of the problems which developed during the Ginna accident, particularly with regard to the creation of a steam bubble in the reactor vessel as a result of depressurization. The potential for uncovering the core, due to a steam bubble in the reactor vessel or elsewhere in the primary system should be addressed. A determination should be made as to whether safety functions performed by the PORV required that it be designated as safety grade and be required to meet all NRC regulations applicable to such safety grade designation, in order to assure safe operation of the reactor.

Response:

Current Commission policy does not require that the PORV and its solenoid operated air valves be designated to be safety grade equipment. The staff has a generic study underway to determine whether PORVs should be required to be safety grade. The PORVs at Ginna will be considered along with all others at the completion of that evaluation. Additional information regarding the installation and operation of the PORV and void formation are contained in Sections 3.3, 4 and 6.1 of NUREG-0916.

Petitioner's Assertion and Request

8. A determination should be made, given the demonstrated unreliability of the PORV, as to whether a reliable method exists for removing decay heat by means of the secondary system, without providing, at the very minimum, one pathway for removing decay heat which consists of safety grade equipment. Such determination should also include an assessment of the reliability of essential auxiliary support systems such as instrument air, and should consider the consequences of loss of off-site power to detemine whether General Design Criteria #17 of 10 CFR Part 50 Appendix A is met.

Response:

The ability of the installed systems at the Ginna plant to provide for a reliable method for removal of decay heat was assessed by the NRC staff. The results of that review are provided in a safety evaluation issued on September 29, 1981, as part of the Systematic Evaluation Program (SEP) review of Topic VII-3, "Systems Required for Safe Shutdown." A copy of that evaluation is attached.

Petitioner's Assertion and Request

9. A determination should be made as to whether the emergency operator procedures set forth in "Westinghouse Emergency Operator Guidelines for Steam Generator Tube Rupture Events" are adequate to protect the public health and safety. Operator delay, or apparent hesitancy, in terminating the HPI (high pressure injection) is of particular concern in relation to the risk of over-pressurization of the reactor pressure vessel as reported in the Speis memorandum (see infra #11) and to the increased reliance on proper functioning of steam generator safety valves. Further, the Ginna emergency procedures should be conformed to the Westinghouse guidelines.

Response:

Since the TMI-2 accident, the staff has been actively reviewing the Westinghouse Emergency Operator Guidelines for steam generator tube ruptures. While the original guidelines from which the Ginna procedures were developed did not specifically address the possibility of a stuck open PORV, the most recent guidelines issued by Westinghouse developed in response to TMI Action Plan item I.C.1, include the consideration of multiple failures, such as PORVs failing open. They also address the possible formation of voids in the reactor vessel. While we have not yet completed our review of these guidelines, we believe they are sufficiently complete that preliminary implementation can begin. We intent to advise the W Owners of this shortly.

With respect to the adequacy of the plant specific procedures in place at the Ginna plant today, the staff evaluation of these procedures is provided in Section 4.2 of NUREG-0916.

Petitioners Assertion and Request

10. The conditions under which the reactor vessel can become over-pressurized in the course of operator action to control an accdient should be clearly specified and a determination made as to whether an automatic response system would decrease the chance of over-pressurization problems from developing and whether the installation of such a system at Ginna is an action that "will provide substantial, additional protection which is required for the public health and safety...." as provided in 10 CFR 50.109.

Response:

This issue is addressed in Section 4.2.9 of NUREG-0916.

Petitioner's Assertion and Request

11. The concerns raised in the Speis memorandum (Themis Speis to Roger Mattson, "Preliminary Evaluation of Operator Action for Ginna SG Tube Rupture Event" dated January 28, 1982, see *infra* Attachment E) regarding problems and potential problems in cooling the reactor following the tube break should be addressed; a determination made as to their safety significance; and necessary corrective action taken. These include the following problems:

    a. the apparent stratification in the B steam generator and its effect on slowing depressurization of the faulted steam generator;

    b. the consequence of an additional coolant system failure, including a leak in the A steam generator or "a secondary side safety/relief valve" sticking open;

    c. the necessity to remove decay heat from the A steam generator by steaming to the atmosphere due to improper functioning of the condensor;

d. the problems associated with the use of the PORV for coolant discharge during "feed and bleed" cooling.

Response:

The issues raised by items a, b, and c are addressed in Section 4.2.8, 4.2.11, 4.2.12 and 8.1 of NUREG-0916.

With regard to item d, had a leak developed in the second ("A") steam generator at Ginna, the need to institute the "feed and bleed" process to assure continued core cooling would have depended upon the leak size and total leak rate of primary coolant out of the primary system.

The staff has been evaluating the capability of operating plants to "feed and bleed" on a generic basis, although no detailed thermal-hydraulic analyses of feed and bleed have been performed for Ginna.

Limited detailed thermal hydraulic analyses have been performed by the industry however, which have shown that feed and bleed is calculated to effectively remove decay heat if sufficient HPI injection and PORV/safety valve relieving capacity is available. These analyses include (1) typical CE (e.g., Calvert Cliffs) plant; (2) B&W 177 FA plant; and (3) Sequoyah Plant (W design).

Recently, the staff evaluated the capability of all operating plants to "feed and bleed" based on each plant's HPI pump capacity and PORV/safety valve relieving capacity. Our evaluation of Ginna concluded that the Ginna plant design has sufficient PORV relieving capacity to depressurize the primary system to below the shutoff head (1475 psi) of the HPI pumps and sufficient HPI pumping capacity to remove decay heat. However, the staff points out that "feed and bleed" cooling is not a design requirement for the plant.

At G'nna, there are procedures in place which instruct the operator on how to reset the safety injection signal in order to enable reestablishing the air supply necessary for PORV operability. The procedure was, in fact, used in reestablishing instrument air which allowed the initial operation of the PORV at Ginna during the tube rupture event.

Additionally, there is a backup nitrogen system which is manually controlled from the control room which can be used to actuate the PORVs in the absence of normal instrument air.

Petitioner's Assertion and Request

12. A determination should be made as to the extent to which failure to implement the TMI Action Plan requirement for instrumentation to allow direct measurement of the water level in the reactor vessel contributed to operator problems in determining proper timing for operating the ECCS pumps and in determining the size of the steam bubble.

Response:

There are several types of water level indication systems being considered by industry and the NRC staff with respect to assisting the operator in making determinations of inadequate core cooling. Some of these systems include level indication in the reactor vessel head region. Had such a measuring device been installed, it likely would have been an aid to the operator. The operators, however, did use the available instrumentation (pressurizer level, reactor coolant system pressure, and vessel upper head thermocouples) in making determinations of the existence of the steam bubble in the reactor vessel head. Furthermore, the core exit thermocouple readings in conjunction with the reactor coolant pressure confirmed that t steam bubble was confined to the reactor vessel head area and the operator's took actions accordingly.

Petitioner's Assertion and Request

13. A full investigation should be made to determine the state of embrittlement of the Ginna reactor pressure vessel to determine the likelihood that over-pressurization will lead to vessel rupture as a consequence of pressurized thermal shock.

Response:

This issue is addressed in Section 3.5 of NUREG-0916.

Petitioner's Assertion and Request

14. The NRC should determine whether the reactor can operate safely without replacement of the steam generator and associated parts of the nuclear steam supply system and whether the newest Westinghouse steam generator design will ameliorate the problems, given the recent problems which have developed with this design at McGuire and at European reactors.

Response:

The issue of steam generator integrity and the results of our evaluation are addressed in Section 5 of NUREG-0916. Based on our conclusion, we see no need at this time to require replacement of the steam generator. We therefore consider no response necessary to the second part of this request.

Petitioner's Assertion and Request

15. The total projected worker exposure should be calculated in advance of NRC approval of RG&E's repairs and a specific plan developed to keep worker exposure as low as reasonably achievable (ALARA). This

should include a determination as to whether time should be allowed for radioactive decay, particularly of Cobalt 58, in the steam generator prior to repairs, in order to prevent unnecessary worker exposure and still allow all necessary repairs to be made.

Response:

In the course of discussions between RG&E and the staff immediately after the event, the licensee estimated that the radiation exposure incurred in the steam generator inspection and repair would be approximately 300 to 350 person-rem. The licensee described his plans to keep exposures as low as reasonably achievable, which included the use of remotely operated tools, extensive pre-planning of evolutions, and practice on special mockups. Members of the regional staff closely monitored the repair efforts to ensure that exposure was kept to a minimum, and as a result, the total exposure incurred in the repair effort was 350 person-rem. The total exposure for the entire outage is expected to be approximately 600 person-rem, which is only slightly higher than the exposure which would be typical for an outage of this magnitude without the additional steam generator repair effort. This exposure is within the expected range for PWR outages.

Petitioner's Assertion and Request

16. An overall safety assessment should be performed before the reactor is allowed to re-start in order that the combined risk of potential failure modes can be determined, in relation to the protection of public health and safety. At a minimum such an assessment should address the following:

a. the degradation of the Ginna steam generators, including the plugging, sleeving and other repairs required to date and planned;

b. the on-going contribution to tube degredation of corrosion arising from AVT control, from condenser leakage, and from the feedwater system (as apposed to the suspected damage from loose pieces of metal in the B steam generator);

c. The lack of a safety grade pathway in the secondary system to remove decay heat;

d. the chance that operator error will lead to over- or under-pressurization of the reactor vessel;

e. the state of reactor vessel embrittlement.

Response:

This request is a summary of several previous items. NUREG-0916 provides a detailed evaluation of item a, b, d and e, along with an overall, integrated assessment of their safety significance. Specifically, Sections 1, 2 and 9 address the contribution by these items to the overall risk to the health and safety of the public posed by the Ginna facility. The SEP evaluation addresses item c. The staff has reviewed these individual assessments and concludes that the return to operation of the R. E. Ginna Nuclear Power Plant is acceptable.

II

The petitioner's request that the staff issue a formal order to suspend the Ginna operating license pending evaluation of safety issues bearing on restart of a formal order was unnecessary to ensure that the licensee did not resume operation until the staff performed its safety evaluation and necessary steps were taken to ensure adequate protection of public health and safety. As a result of a meeting on February 10, 1982 between the staff and representatives of the licensee, and other subsequent discussion, Rochester Gas and Electric Corporation agreed to to provide a complete evaluation of the event and a basis for restart of the Ginna plant. The licensee further agreed that this information would be submitted for review and approval by the staff prior to restart. This commitment was confirmed in a letter (copy attached) to the licensee from the Director of the Division of Licensing on February 24, 1982.

In light of this commitment by the licensee to delay restart until receipt of approval by the staff, the issuance of a show cause order or the suspension of the license was unnecessary. The Ginna plant has remained shut down pending approval by the staff for restart, and no formal action has been necessary to enforce the licensee's commitment.

A copy of this decision will be filed with the Secretary for the Commission's review in accordance with 10 CFR 2.206(c). As provided in this regulation, the decision will become the final action of the Commission twenty-five (25) days after issuance, unless the Commission, on its own motion, institutes review of the decision within that time.

Harold R. Denton

Harold R. Denton, Director
Office of Nuclear Reactor Regulation

Dated at Bethesda, Maryland,
this 22nd day of May, 1982.

Attachments:
1. NRC letter dtd. September 29, 1981
   from D. Crutchfield to J. Maier,
   RG&E enclosing staff's evaluation
   related to Safe Shutdown Systems.
2. NRC letter dtd. February 24, 1982
   from D. Crutchfield to J. Maier,
   RG&E relating to Ginna Steam
   Generator event evaluation and
   basis for restart.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

September 29, 1981

Docket No. 50-244
LS05-81-09-077

Mr. John E. Maier
Vice President
Electric & Steam Production
Rochester Gas & Electric Corporation
89 East Avenue
Rochester, New York 14649

Dear Mr. Maier:

SUBJECT: GINNA - SEP TOPICS V-10.B, RHR SYSTEM RELIABILITY, V-11.B, RHR INTERLOCK REQUIREMENTS, AND VII-3, SYSTEMS REQUIRED FOR SAFE SHUTDOWN (SAFE SHUTDOWN SYSTEMS REPORT)

Enclosed is the revised evaluation of Safe Shutdown Systems, incorporating, where appropriate, comments from your letter dated June 23, 1981. Changes from the previous revision are marked by a line in the margin.

The issue of high pressure/low pressure interfaces and RHR interlock requirements (SEP Topics V-11.A and V-11.B) was the subject of a recent staff safety evaluation transmitted to you by letter dated July 22, 1981. The safe shutdown system report has been modified to be consistent with the positions established in that letter.

Since the conclusions of our evaluation are dependent on the ultimate ability of the plant to shut down with the specified minimum equipment, the staff considers that the operating procedures should detail how these systems would be used for the cooldown if non-safety grade systems were unavailable. In particular, instructions for controlled operation of the power operated relief valves with loss of control air should be provided.

As discussed in Appendix A of the Safe Shutdown Systems Report, contact with raw water can lead to degradation of steam generator tubes. Accordingly, use of lake water as feedwater should be minimized to the extent possible, such as by proceeding to cold shutdown rather than staying at hot shutdown. Operating procedures should provide guidance concerning the potential for tube damage to ensure generator integrity.

The staff discussion of passive failures in fluid systems is included to assist reviewers of such topics as missiles, pipe breaks and seismic events, who use the safe shutdown systems report as input to their evaluation. As clearly stated in the report, passive failures are not a design basis for safe shutdown with loss of offsite power and a single active failure.

In summary, the following staff positions will be carried into the integrated assessment:

1. To fulfill the safety objective of reliable plant shutdown capability using safety-grade equipment, the licensee should ensure that plant operating procedures provide guidance on performing shutdown and cooldown functions with the systems identified in the minimum list. In addition, procedures for operation of the power-operated relief valves with a loss of the plant air system should be provided.

2. The licensee must develop plant operating/emergency procedures for conducting a plant cooldown from outside the control room. This procedure may be developed in conjunction with the fire protection reviews, if appropriate.

3. The operating procedures for the Ginna plant should be modified to provide suitable precautions for the operator concerning use of lake water as feedwater and the potential for tube damage and leakage.

We now consider the safe shutdown system evaluation to be complete. This evaluation will be a basic input to the integrated safety assessment for your facility. This assessment may be revised in the future if your facility design is changed or if NRC criteria relating to this topic are modified before the integrated assessment is completed.

Sincerely,

Thomas V. Wambach
for Dennis M. Crutchfield, Chief
Operating Reactors Branch No. 5
Division of Licensing

Enclosure:
As stated

cc w/enclosure:
See next page

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LS05-81-09-077

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Sincerely,

Thomas V. Wambach
for
Dennis M. Crutchfield, Chief
Operating Reactors Branch No. 5
Division of Licensing

Enclosure:
As stated

cc w/enclosure:
See next page

SEP REVIEW

OF

SAFE SHUTDOWN SYSTEMS

FOR THE

R. E. GINNA NUCLEAR POWER PLANT

REVISION 3

AUGUST 1981

TABLE OF CONTENTS

1.0 INTRODUCTION

The Systematic Evaluation Program (SEP) review of the "safe shutdown" subject encompassed all or parts of the following SEP topics, which are among those identified in the November 25, 1977 NRC Office of Nuclear Reactor Regulation document entitled "Report on the Systematic Evaluation of Operating Facilities:"

1. Residual Heat Removal System Reliability (Topic V-10.B)

2. Requirements for Isolation of High and Low Pressure Systems (Topic V-11.A)

3. Residual Heat Removal Interlock Requirements (Topic V-11.B)

4. Systems Required for Safe Shutdown (Topic VII-3)

5. Station Service and Cooling Water Systems (Topic IX-3)

6. Auxiliary Feedwater System (Topic X)

The review was primarily performed during an onsite visit by a team of SEP personnel. This onsite effort, which was performed during the period June 14-16, 1978, afforded the team the opportunity to obtain current information and to examine the applicable equipment and procedures.

The review included specific system, equipment and procedural requirements for remaining in a hot shutdown condition (reactor greater than 1% subcritical, temperature above 540°F) and for proceeding to a cold shutdown condition (temperature less than 200°F). The review for transition from operating to hot shutdown considered the requirement that the capability exists to perform this operation from outside the control room. The review was augmented as necessary to assure resolution of the applicable topics, except as noted below:

Topic V-11.A (Requirements for Isolation of High and Low Pressure Systems) was examined only for application to the residual heat removal (RHR) system. Other high pressure/low pressure interfaces were not investigated.

Topic IX-3 (Station Service and Cooling Water Systems) was only reviewed to consider redundancy and seismic and quality classification of cooling water systems that are vital to the performance of safe shutdown system components. (No discussion of Topic IX-3 is included in this report. The information gathered during the safe shutdown review will be used to resolve this topic in a separate evaluation.

Topic X (Auxiliary Feedwater System) was reviewed as part of the safe shutdown systems evaluation in terms of ability to remove decay heat. Other aspects of the topic will be resolved as part of the design basis event review, other SEP topic reviews and as part of the TMI Task Action Plan.

The criteria against which the safe shutdown systems and components were compared in this review are taken from the: Standard Review Plan (SRP) 5.4.7, "Residual Heat Removal (RHR) System" and Branch Technical Positic RSB 5-1, Rev. 1, "Design Requirements of the Residual Heat Removal System." These documents represent current staff criteria for the review of applications for operating licenses.

This comparison of the existing systems against the current licensing criteria led naturally to at least a partial comparison of design criteria, which will be input to SEP Topic III-1, "Classification of Structures, Components and Systems (Seismic and Quality)."

As noted above, the six topics were considered while neglecting possible interactions with other topics and other systems and components not directly related to safe shutdown. For example, Topics II-3.B (Flooding Potential and Protection Requirements), II-3.C (Safety-Related Water Supply), III-4.C (Internally-Generated Missiles), III-5.A (Effects of Pipe Break on Structures, Systems and Components Inside Containment), III-6 (Seismic Design Considerations), III-10.A (Thermal-Overload Protection for Motors of Motor-Operated Valves), III-11 (Component Integrity), III-12 (Environmental Qualification of Safety-Related Equipment), and V-1 (Compliance with Codes and Standards) are among several topics which can be affected by the results of the safe shutdown review or can have a safety impact upon the systems which were reviewed. The safe shutdown review is used as input to several of the aformentioned topic evaluations. This review did not cover, in any significant detail, the reactor protection system nor the electrical power distribution system, both of are evaluated under other SEP topic reviews.

The major factor in assessing the safety margin of any of the SEP facilities depends upon the ability to provide adequate protection for postulated design basis events (DBEs). The SEP topics provide a major input to the DBE review, both from the standpoint of assessing the probability of certain events and that of determining the consequences of events. As examples, the safe shutdown topics pertain to the listed DBEs (the extent of applicability will be determined during the SEP DBE review for Ginna):

Topic	DBE Group*	Impact Upon Probability Or Consequences of DBE
V-10.B	VII (Spectrum of Loss-of-Coolant Accidents)	Consequences
V-11.A	VII (Defined above)	Probability
V-11.B	VII (Defined above)	Probability
VII-3	All (Defined as a generic topic)*	Consequences
IX-3	III (Steam Line Break Inside Containment) (Steam Line Break Outside Containment)	Consequences
	IV (Loss of AC Power to Station Auxiliaries) (Loss of all AC Power)	Consequences
	V (Loss of Forced Coolant Flow) (Primary Pump Rotor Seizure) (Primary Pump Shaft Break)	Probability
	VII (Defined above)	Consequences

*For a listing of DBE groups and generic topics, see Reference 10.

Topic	DBE Group*	Impact Upon Probability Or Consequences of DBE
X	II (Loss of External Load) (Turbine Trip) (Loss of Condenser Vacuum) (Steam Pressure Regulator Failure [closed]) (Loss of Feedwater Flow) (Feedwater System Pipe Break)	Consequences
	III (Defined above)	Consequences
	IV (Defined above)	Consequences
	V (Defined above)	Consequences
	VII (Defined above)	Consequences

The completion of the safe shutdown topic review (limited in scope as noted above) provides significant input in assessing the existing safety margins for the Ginna Station.

Piping System Passive Failures

The NRC staff normally postulates piping system passive failures as 1) accident initiating events in accordance with staff positions on piping failures inside and outside containment, 2) system leaks during long term coolant recirculation following a LOCA, and 3) failures resulting from hazards such as earthquakes, tornado missiles, etc. In this evaluation, certain piping system passive failures have been assumed beyond those normally postulated by the staff, e.g. the catastrophic failure of moderate energy systems. These assumptions were made to demonstrate safe shutdown system redundancy given the complete failure of these systems in order to facilitate future SEP reviews of DBEs and other topics (such as missiles, pipe breaks or seismic events) which will use the safe shutdown evaluation as a source of data for the SEP facilities. SRP 5.4.7 and BTP RSB 5-1 do not require the assumption of piping system passive failures.

Credit for Operating Procedures

For the safe shutdown evaluation, the staff may give credit for facility operating procedures as alternative means of meeting regulatory guidelines. Those procedural requirements identified as essential for acceptance of an SEP topic or DBE will be carried through the review process and considered in the integrated assessment of the facility. At that time, we will decide which procedures are so important to acceptance of a topic that an administrative method must be established to ensure that in the future, operating procedures are not changed without appropriate consideration of their importance to the SEP topic evaluation.

2.0 DISCUSSION

2.1 Normal Plant Shutdown and Cooldown

A normal shutdown from full power to hot shutdown is accomplished with the use of the operating procedure "Normal Shutdown to Hot Shutdown." The shutdown from power is done by borating the reactor coolant system via the charging pumps to the amount that will maintain control bank D above the low insertion limit and ensure that the axial flux difference will remain within its target band.

The first main feedwater pump is removed from service at approximately 50% power. The power reduction is continued on one feedwater pump. At 50 Mwe the auxiliary load is transferred to auxiliary transformer No. 12 with a feed from the 34.5Kv switchyard; at this power level the feedwater flow is transferred to the feedwater bypass valves and power is reduced to the point where the steam dump mode switch is placed in manual to control the steam generator pressure at 1005 psig. The generator and turbine are taken out of service at 15 Mwe.

The steam is directed to the condenser through the steam dump valves and the feedwater is supplied from the auxiliary feedwater pumps and the control rods and shutdown bank are inserted to make the reactor subcritical. Throughout the shutdown to hot shutdown the primary water inventory has been maintained automatically by the chemical volume control system (CVCS) and charging pumps.

The second phase of a plant shutdown from hot shutdown to cold shutdown, i.e., primary coolant less than 200°F, is described in "Plant Shutdown from Hot Shutdown to Cold Shutdown." Reactor coolant inventory is automatically maintained with makeup coolant pumped from the volume control tank (VCT) to the primary system with the charging pumps. An altarnative source of borated water is available from the RWST. Reactor coolant temperature is controlled by dumping steam through the condenser steam dumps (preferred) or the atmospheric relief valves.

Prior to utilizing the residual heat removal (RHR) system, boron samples are taken and boron concentration adjusted to verify a reactivity transient will not occur when the RHR system is cut in to the reactor coolant system (RCS). Technical Specifications 3.3.1.3 and 3.15.1 state that the reactor vessel overpressure protection must be put in service and one safety injection pump removed from service when RCS cold leg temperature is ≤ 330°F. Reactor pressure is controlled at 360 psig by letdown pressure controller PCV-135. At this point the RHR system is put in service by opening the suction isolation valves (700 and 701) from the hot leg, starting the RHR pumps, and opening the discharge isolation valves (720 and 721).

The RHR flow is adjusted to maintain a cooldown rate at less than 50°F/hr. The heat from the RHR system is transferred through RHR heat exchangers to the component cooling water system and then from the component cooling water system through the component cooling heat exchangers to the service water system. The minimum pump head on the RHR pumps is 150 psig, the component cooling water system operating pressure is 80 psig, and the service water system operating pressure is 75 psig; therefore, in the event of an RHR heat exchanger tube leak, the flow of impurities would be away from the primary coolant system.

2.2 Shutdown and Cooldown with Loss of Offsite Power

The shutdown during a station blackout (loss of offsite power) to hot shutdown is achieved with the emergency procedure "Station Blackout Operation." A station blackout results in loss of the reactor coolant pumps, circulating water pumps, condensate pumps, and main feedwater pumps. Feedwater is maintained by the automatic start of the auxiliary feedwater pumps after the automatic start of the diesel generators. A component cooling pump and service water pump are also restarted.

The operator must restart the instrument air compressors and charging pumps and restore emergency power to the non-Class 1E instrument buses. Class 1E instrument buses are automatically restored to emergency power.

The primary inventory is maintained by the automatic operation of the charging and letdown system. The core is cooled by natural circulation of the primary coolant; natural circulation was demonstrated successfully on January 18, 1970 during the startup test program. Heat is removed from the primary coolant through the steam generators; and secondary flow is from condensate storage tanks via the auxiliary feedwater system and the steam is discharged from the atmospheric relief valves. The operating procedure "Plant Shutdown from Hot Shutdown to Cold Shutdown During Blackout," is used when it is determined that the plant should be placed in cold shutdown. Since the equipment is the same, this procedure is much like the normal procedure for cold shutdown, except the condenser steam dump is not available and a caution is noted to allow more time for boration since the primary flow is low (natural circulation). The station did experience a loss of offsite power on October 21, 1973; disturbances on the instrument buses caused excessive operation of the auxiliary feedwater pumps, and this resulted in an excessive cooldown rate and the generation of a safety injection signal. All other equipment operation and operator action was reported as correct in abnormal occurrence Report No. 73-9 of October 31, 1973.

3.0 CONFORMANCE WITH BRANCH TECHNICAL POSITION 5-1 FUNCTIONAL REQUIREMENTS

The current NRC criteria used in the evaluation of the design of the systems required to achieve cold shutdown for a new facility are listed in Standard Review Plan (SRP) 5.4.7, Regulatory Guide 1.139, Revision 0, "Guidance for Residual Heat Removal," and Branch Technical Position RSB 5-1. The following paragraphs give a point by point comparison of Branch Technical Position (BTP) RSB 5-1 functional requirements to the shutdown systems at the R. E. Ginna Plant. The positions in Regulatory Guide 1.139 are consistant with the functional requirements of BTP RSB 5-1. The remaining BTP provisions will be addressed in Section 4.

BRANCH TECHNICAL POSITION (BTP)

"A. Functional Requirements

"The system(s) which can be used to take the reactor from normal operating conditions to cold shutdown shall satisfy the functional requirements listed below.

1. The design shall be such that the reactor can be taken from normal operating conditions to cold shutdown using only safety-grade systems. These systems shall satisfy General Design Criteria 1 through 5.
2. The system(s) shall have suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electrical power system operation (assuming onsite power is not available) the system function can be accomplished assuming a single failure.
3. The system(s) shall be capable of being operated from the control room with either only onsite or only offsite power available with an assumed single failure. In demonstrating that the system can perform its function assuming a single failure, limited operator action outside of the control room would be considered acceptable if suitably justified.
4. The system(s) shall be capable of bringing the reactor to a cold shutdown condition, with only offsite or onsite power available, within a reasonable period of time following shutdown, assuming the most limiting single failure."

The capability of the safe shutdown systems for the Ginna Station to meet these criteria is discussed below:

3.1 Background

A "safety-grade" system is defined, in the NUREG-0138 (Reference 11) discussion of Issue #1, as one which is designed to seismic Category I (Regulatory Guide 1.29), quality group C or better (Regulatory Guide 1.26), and is operated by electrical instruments and controls that meet Institute of Electrical and Electronics Engineers Criteria for Nuclear Power Plant Protection Systems (IEEE 279). The Ginna Station was constructed prior to the issuance of Regulatory Guides 1.26 and 1.29 (as Safety Guides 26 and 29 on 3/23/72 and 6/7/72, respectively). Also Proposed IEEE 279, dated August 30, 1968, was issued late in the construction phase of the facility. Therefore, for this evaluation, the systems which should be "safety-grade" are the systems identified in Table 3.1 and in the following minimum list of safe shutdown systems.

General Design Criterion (GDC) 1 requires that these systems be designed, fabricated, erected, and tested to quality standards, that a Quality Assurance (QA) program be implemented to assure these systems perform their safety functions, and that appropriate records of design, fabrication, erection, and testing be kept.

Regulatory Guide (RG) 1.26 provides the current NRC criteria for quality group classification of safety-related systems. Table 3.1 provides a comparison of the Ginna safety-grade shutdown systems with RG 1.26. Although RG 1.26 was not in effect when Ginna was constructed, the licensee has since classified the systems at Ginna in accordance with this guide. Therefore, even though the safety-related systems at Ginna were not designed, fabricated, erected and tested using RG 1.26, the maintenance and repair of the classified systems is currently conducted in accordance with this guide.

In the Final Safety Analysis Report, the licensee identified classification criteria according to system and component importance. Those items vital to safe shutdown and isolation of the reactor or whose failure might cause or increase the severity of a loss-of-coolant accident or result in an uncontrolled release of excessive amounts of radioactivity were designated Class I. Those items important to reactor operation but not essential to safe shutdown and isolation of the reactor or control of the release of substantial amounts of radioactivity were designated Class II. Those items not related to reactor operation or safety were designated Class III. This classification system is reflected in Table 3.1.

At the time the Ginna Station was licensed, the NRC (then AEC) criteria for QA were being developed. However, the QA program for construction of Ginna was reviewed by the staff and by the Advisory Committee on Reactor Safeguards (Reference 1). The QA program for operation of Ginna, which is SEP Topic XVII, has been previously approved by the staff (Reference 2).

A complete set of as-built facility plant and system diagrams including arrangement and structural plans is maintained by the licensee for the life of the reactor.

GDC 2 states that structures and equipment important to safety shall be designed to withstand the effects of natural phenomena without loss of capability to perform their safety function. Natural phenomena considered are: hurricanes, tornadoes, floods, tsunami, seiches, and earthquakes.

During construction of Ginna Station, measures were taken in the plant design to protect against high winds, sudden barometric pressure changes, seiches, and other natural phenomena. Although the Ginna Station was not specifically designed against tornadoes, the original staff evaluation for Provisional Operating License assessed the potential effects of tornadoes on the facility. The effects of tornadoes will be reevaluated during the course of the SEP in Topics II-2.A, "Severe Weather Phenomena," III-2, "Wind and Tornado Loadings," and III-4.A, "Tornado Missiles."

The effects of flood on the Ginna Station were considered during the Provisional Operating License review. Additionally, floods and flood effects will be reassessed in the SEP review under Topics II-3.B, "Flooding Potential and Protection Requirements," and III-3, "Hydrodynamic Loads."

Regarding seismic design of the Ginna Station, all systems and components designated Class I were designed so that there is no loss of function in the event of the maximum potential ground acceleration acting in the horizontal and vertical directions simultaneously. Within the SEP review, the potential for and consequences of a seismic event at the Ginna site will be reassessed under several review topics (SEP Topics II-4, III-6, III-11).

GDC 3 requires structures, systems, and components important to safety to be designed and located to minimize the effects of fires and explosions.

The Ginna fire protection reevaluation resulting from the Browns Ferry fire is currently underway by the NRC Staff. The results of this reevaluation will be integrated into the SEP assessment of Ginna Station.

GDC 4 requires that equipment important to safety be designed to withstand the effects of environmental conditions for normal operation, maintenance, testing, and postulated accidents. Also, the equipment should be protected against dynamic effects, including internal and external missiles, pipe whip, and fluid impingement.

GDC 4 was considered in the POL review of Ginna, and the facility was found to meet this criterion. Additionally, the SEP will consider the various aspects of this criterion when reviewing topics III-12, "Environmental Qualification of Safety-Related Equipment," III-5.A, "Effects of Pipe Breaks Inside Containment," III-5.B, "Pipe Breaks Outside Containment," and III-4, "Missile Generation and Protection."

GDC 5 is not applicable for the Ginna Station because it does not share any equipment with other facilities.

The BTP RSB 5-1 functional requirements focus on the safety-grade systems that can be used to take the reactor from operating conditions to cold shutdown. The staff and licensee developed a "minimum list" of systems necessary to perform this task. Although other systems may be used to perform shutdown and cooldown functions, the following list is the minimum number of systems required to fulfill the BTP RSB 5-1 criteria:

(a) Reactor protection system

(b) Auxiliary feed system

(c) Main steam system (safety, isolation and atmospheric dump valves)

(d) Service water system

(e) Chemical and volume control system

(f) Component cooling water system

(g) Residual heat removal system

(h) Instrumentation for shutdown/cooldown*

(i) Emergency power (AC and DC) and control power for the above systems and components

In addition to these systems, other safety-grade and nonsafety-grade equipment may function as backup for the above listed systems and components. The following section will discuss these safety-grade systems and the nonsafety-grade systems which may function as backup. (Table 3.4 lists the power supplies and location of major safe shutdown components.)

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*For a minimum list of safe shutdown instrumentation, see Section 3.3

3.2 Functional Requirements

Five basic functions, or tasks, are required to proceed from plant operation to hot shutdown and to cold shutdown. These functions are identified in Table 3.2. A discussion of each function and associated alternate methods is provided below.

Control of Reactor Power

Power generation in the reactor core is terminated by either chemical addition (boration) or insertion of control rods. During a planned shutdown, power would be reduced in an orderly manner by boration followed by control rod insertion. For rapid reactor shutdown, the control rods can be manually or automatically tripped. Boration is accomplished with the chemical and volume control system (CVCS) which is discussed under Primary System Control, below. The control rods are controlled by the reactor control and protection system.

The Reactor Protection System (RPS) is designed on a channelized basis to provide physical and electrical isolation between redundant reactor trip channels. Each channel is functionally independent of every other channel and receives power from two independent sources. The power sources for the RPS are the instrument buses which can receive power from either onsite or offsite sources. The RPS fails safe (tripped) on loss of power. The system can be manually tripped both from the control room and from other locations outside the control room. The RPS is designed so that a single failure will not prevent a reactor trip. Initiation of a reactor trip causes the insertion of sufficient reactor control rods to make the core subcritical from any credible operating condition assuming the most reactive control rod remains in the fully withdrawn position.

The design of the RPS, as well as safe shutdown-related electrical control and power systems, is evaluated under other topics in the SEP.

Core Heat Removal

In hot shutdown, and during cooldown prior to residual heat removal system operation, core decay heat is transferred to the steam generators by forced convection flow of reactor coolant using the reactor coolant pumps. If offsite power is unavailable, core decay heat can be adequately removed by natural circulation flow. (See Section 4.4 for a discussion of natural circulation.)

In the final stages of plant cooldown and for long-term cooling, decay heat is removed by the residual heat removal (RHR) system. Heat from the RHR system is transferred to the ultimate heat sink (Lake Ontario) via the component cooling water system and the service water system.

The Residual Heat Removal (RHR) system consists of a single drop line from the reactor coolant system (RCS) (hot leg) through two pumps and their associated heat exchangers and back to the RCS via a single header. Each pump can be manually cross-connected to the alternate heat exchanger for increased reliability. Normal cooldown of the RCS is accomplished by operating both pumps and heat exchangers; however, a lesser cooldown rate can be achieved with only one pump. One heat exchanger can affect cooldown approximately 20 hours after shutdown. Each RHR pump is supplied power from separate redundant 480V emergency buses. The system is normally operated from the control room.

The single RHR cooling suction line from the RCS and single discharge line to the RCS render the RHR system susceptible to single failure of the in-line suction valves (700, 701) in the closed position and passive failures of either suction or discharge lines. (Valves 700 and 701, which are inside containment, can be manually operated to overcome a motor operator or power supply failure.) Although these failures would render the RHR mode of decay heat removal inoperable, the alternate means of decay heat removal using the steam generators, as discussed below in the Component Cooling Water Section, is still available as a backup. For the case of a failure of valves 700 or 701 or a pipe break downstream of these valves, an alternate flow path for core cooling is available via the RHR cooling discharge line and the high pressure safety injection (HPSI) pumps (Reference 13). Reference 13 also lists other means of core decay heat removal should the RHR, or CCW, system become inoperable. These methods have a low heat removal capability but could be used to supplement steam generator heat removal until the decay heat rate was low enough. These methods are heat removal via the CVCS nonregenerative and excess letdown heat exchangers (requires component cooling water) and cooldown flow from the pressurizer to the containment via the pressurizer relief valves with coolant injection from the safety injection or chemical and volume control systems. If a pipe break upstream of valves 700 and 701 should occur, (i.e. a LOCA), the core could be adequately cooled by means of the RHR containment recirculation mode.

The Component Cooling Water (CCW) system consists of two pumps, heat exchangers, a surge tank and connecting valves and piping. During normal full power operation, or for post-accident operation, one component cooling pump and one component cooling heat exchanger accommodate the heat removal loads. The standby pump and heat exchanger provide 100 percent backup. Both pumps and both heat exchangers are utilized to remove the residual and sensible heat during plant shutdown. If one of the pumps or one of the heat exchangers is not operative, safe operation of the plant is not affected; however, the time for cooldown is extended.

The surge tank accommodates expansion, contraction and inleakage of water, and ensures a continuous component cooling water supply until a leaking cooling line can be isolated. Because the tank is normally vented to the atmosphere, a radiation monitor in the component cooling pump inlet header annunciates in the control room and closes a valve in the vent line in the unlikely event that the radiation level reaches a preset level above the normal background.

During shutdown, the CCW system supplies cooling water to the RHR pumps and heat exchangers. Although the CCW pumps and heat exchangers are redundant, they are connected by single pipe headers. A passive failure in the single header portion of the system would disable the system and render the normal post-accident mode of long-term cooling inoperable. However, current criteria for piping system passive failures do not require the assumed passive failure of moderate energy systems (like the CCW) under post-accident conditions, although system leaks are assumed. Therefore, the CCW system must only be required to cope with normal system leakage in post-accident operation.

We also considered the effects of such a passive failure during a cooldown of the plant. In this case, with the reactor vessel head installed, the RCS temperature would rise to greater than 200°F and decay heat could continue to be removed via the steam generator atmospheric relief valves using natural circulation. In this case, steam generator feed would be accomplished by the Auxiliary Feed System (AFS). The plant could remain in this condition while CCW repairs were made. For normal decay heat removal when the reactor vessel head is removed, adequate cooling can be provided by keeping the core flooded (using various systems such as RHR and CVCS) while repairs are made to the CCW piping. The CCW system is accessible for repairs and can be filled with water in less than two hours after the repairs are completed starting with a completely drained system (Reference 7, page 9.3-18).

Therefore, although the CCW would be disabled by a large pipe rupture, this failure is not postulated under post-accident conditions and the Ginna facility has acceptable alternate means to remove core decay heat for normal plant cooldown. Passive failures are not a design requirement for decay heat removal in accordance with BTP RSB 5-1. Since the CCW is a moderate energy system, a passive failure would most probably result in a leak not in a pipe rupture (Reference 14). This is discussed further in SEP Topic IX-3 "Station Service and Cooling Water Systems".

The CCW pumps receive power from the redundant 480V emergency buses and the system is normally operated from the control room.

The Service Water System (SWS) circulates water from the screen house on Lake Ontario to various heat exchangers and systems in the containment, auxiliary and turbine buildings. These buildings are Class I structures except for the turbine building. The system has four pumps, three of which have the capacity to supply normal cooling loads. Under accident conditions, two pumps are required to supply essential loads. The SWS piping is arranged so that there are at least two flow paths to each essential load, and nonessential loads are automatically isolated on a safeguards actuation signal. Valving is provided to isolate any single failure and permit continued operation of the system. The SWS valve lineup essentially splits the system into two independent trains. Safety-related equipment (diesel generators, AFS supply, containment ventilation coolers, etc.) is split between the trains so that loss of one SWS loop will affect only half of the redundant safety-related equipment capacity.

The SWS header in the turbine building is not a Class I system. Isolation valves in the auxiliary building are provided to automatically isolate the turbine building header in the event of a safeguards actuation signal. These valves and other motor-operated valves which isolate nonessential SWS loads, as well as the system pumps, are operable from the control room.

Power for the SWS pumps is provided by the 480V emergency buses which can be supplied by the emergency diesels or offsite power. One pump per diesel is automatically started during post-accident diesel load sequencing.

Steam Generator Heat Removal

Boiling of feedwater in the steam generator is the dominant mode of removing primary system heat. Normally, the energy in the steam is removed in the turbine and the main condenser. After the turbine is tripped, the turbine bypass system provides a controlled steam release directly to the condenser. The ultimate heat sink for the condenser is the circulating water system (Lake Ontario). When the condenser is not available, the steam is released directly to the atmosphere through either the atmospheric dump valves or code safety valves. As the steam is lost, a continuing source of feedwater is required.

The safety-grade shutdown components associated with the Main Steam System are the main steam isolation valves (MSIV), the steam safety valves, and the steam atmospheric dump valves. Each of the two Ginna steam generators is equipped with an air-operated, solenoid controlled

MSIV, four code safety valves, and one air-operated atmospheric dump valve. By shutting the MSIVs from the control room, the operator can limit the shutdown and cooldown of the plant to the use of redundant main steam equipment*. The MSIVs fail shut on loss of control air. For core decay heat removal with natural circulation of the reactor coolant, only one steam generator and one of its four safety valves are required to remove core decay heat a few seconds after reactor trip. One atmospheric steam dump valve which can be operated from the control room using the plant compressed air system is sufficient for maintaining hot shutdown or for cooldown of the RCS below hot shutdown conditions. However, the plant air systems are not Class I so manual opening of the atmospheric dump would be required if the shutdown procedures were limited to use of safety grade equipment alone. Since there is no need to proceed immediately from hot shutdown to cold shutdown, an operator is not required to man an atmospheric dump within the first half hour to several hours after achieving hot shutdown. We have determined that this manual operation of the atmospheric dumps is acceptable under the provisions of the BTP.

There are other paths for steam removal from the steam generator. Around 0.5% of design steam flow is rejected through the auxiliary feed pump turbine. It has been demonstrated that hot shutdown heat removal can be accomplished through steam generator blowdown to the flash tank. Other small bleed valves can be manually opened to augment steam release.

* The operator would not normally do this unless the systems which are normally used for shutdown and cooldown were not operable.

Also, as mentioned in Reference 13, the steam generators could be used as heat exchangers by filling them with water on the secondary side (after adding support to the main steam lines) to remove core heat at low RCS temperatures.

Feedwater

Under normal conditions, feedwater is pumped from the main condenser to the steam generator by the condensate pumps and main feedwater pumps. When main feedwater is not available, during operation at low reactor power levels, or during plant startup and shutdown, the auxiliary feed system is used to supply the steam generators.

The Auxiliary Feed System (AFS) is divided into two independent trains. One train is supplied by a steam turbine-driven pump; the other train is supplied by two motor-driven pumps powered from separate 480V buses. Each motor-driven pump can provide 100% of the AFS flow required for decay heat removal through its normally open motor-operated discharge valve; and, via parallel, AC powered cross-connect valves, the flow can be directed to either steam generator. The turbine-driven pump can supply 200% of the required system flow and is lined up to discharge to both steam generators. It can be cross-connected to either motor-driven pump discharge line by means of manual valves. The lube oil for the turbine is supplied from an AC-driven pump or a backup DC pump. While the motor-operated valves associated with the motor-driven pumps are AC powered with each motor and its associated valves powered by redundant AC sources, the motor-operated discharge valve and steam supply valves for the turbine-driven pump are DC powered. The air-operated valves in the turbine-driven pump discharge lines (one valve for each steam generator) are controlled by DC powered electropneumatic converters and fail in the open position on loss of air.

The main source of water to the AFS is via gravity feed from the condensate storage tanks (CST); the backup, seismic Class I, supply is taken from the service water system (SWS) via separate lines: one for the turbine-driven pump, and one for the two motor-driven pumps. Manual action is required to isolate the AFS pump suctions from the nonseismic CST supply lines and to line up the pumps to the SWS. The manual valve alignment of the AFS to the SWS can be performed within 4 minutes by an operator dispatched from the control room. This time is based on an actual walk-through at the plant. A feedwater line break analysis by the licensee using conservative assumptions (Reference 3) concluded that a 10-minute delay in initiating AFS flow resulted in acceptable consequences. If both steam generators were available this time delay could be doubled. Therefore, the NRC staff has determined that the manual lineup of the AFS suction to the SWS is justified under the "limited operator action outside the control room" provision of the BTP. All other functions of the AFS can be initiated, controlled and monitored from the control room.

Because of the nonseismic CST supply lines to the AFS pump, the possibility of a seismic event, both (1) severing the CST supply lines, and (2) initiating events which would lead to the automatic start of the AFS pumps (i.e., loss of main feed), was considered from the standpoint of causing AFS pump burnup through loss of suction fluid. In this case, the standby auxiliary feed system, described below, is available to feed the steam generators for decay heat removal.

The electrical power supply for the motor-driven pumps is derived from the separate redundant 480V emergency buses which can receive power from either onsite or offsite sources.

As a result of the review of the affects of pipe breaks outside of containment, the licensee installed a standby auxiliary feed system (SAFS). The SAFS uses two motor-driven pumps which can be aligned to separate SWS loops by motor-operated valves remotely operable from the control room. The SAFS provides the same features as the previously described motor-driven auxiliary feed pumps with regard to functional capability and power supply diversity; it is manually actuated from the control room. The SAFS has been installed and approved for use by the NRC staff. The staff evaluation of the SAFS is contained in Reference 16.

Primary System Control

It is necessary to control pressurizer level and pressure during the plant shutdown and cooldown. Pressurizer level is controlled with the chemical and volume control system. Pressure is controlled by the pressurizer heaters, to prevent pressure decrease, and by the pressurizer relief valves to prevent overpressurizing the reactor coolant system.

From the standpoint of RCS coolant inventory, an overpressurization transient is less likely if a plant cooldown is in progress because the reactor coolant volume decreases as the system temperature is lowered, and makeup to the reactor coolant system is needed to keep the pressurizer from emptying.

The Chemical and Volume Control System (CVCS) provides borated water from the boric acid tanks or the refueling water storage tank (RWST) through three positive displacement charging pumps to the RCS via (1) the normal charging lines (to either a hot or a cold RCS leg), (2) an alternate charging line, (3) alternate pressurizer spray line, or (4) the reactor coolant pump (RCP) seals. To avoid the use of the nonsafety-grade air system, the licensee has proposed to charge to the RCS via the RCP seal path which has no air-operated valves or, as a backup method, by charging through the air-operated valves in the normal charging line. Even though they fail shut on loss of air pressure, these valves are designed to allow charging flow to pass through them into the RCS. The capacity of one pump (46 gpm) is sufficient to compensate for contraction of the RCS coolant during normal cooldown. Boration following shutdown from power operation is not required until after approximately 24 hours because of xenon inventory in the core; however, without considering xenon, one charging pump alone can provide cold shutdown boration requirements immediately following reactor shutdown. Water for the charging pumps would be supplied from the RWST by manually opening valve 358 to bypass an air-operated valve in the charging pump suction lines. The charging pumps can be controlled locally or from the control room. Power for the charging pumps is supplied via the emergency buses from either onsite or offsite power sources. Because of the length of time available to allow manual opening of valve 358 before boration of the core is necessary, we have concluded that this operation—is allowable under the provisions of BTP 5-1.

The charging pumps discharge into a common pressure pulse dampening accumulator which renders the system susceptible to a single passive failure which could prevent charging for boration and coolant contraction during cooldown. Should this occur, a redundant method of charging and boration exists by means of the high pressure safety injection (HPSI) system. Any of the three HPSI pumps can be lined up from the control room to take a suction on the RWST or the boric acid tanks and to inject borated water into the RCS via the HPSI lines. If RCS pressure is greater than HPSI discharge pressure (1750 psig), the pressurizer can be blown down through one of the two redundant power-operated pressurizer relief valves to reduce RCS pressure.

The RCS is protected from overpressurization during transients which may cause the steam generator MSIVs to shut by two redundant Pressurizer Safety Valves and two redundant Power-Operated Relief Valves (PORVs). These transients are reviewed as SEP design basis events. The PORVs are dual setpoint valves operable from the control room; the dual setpoint feature has been added to the PORVs to mitigate potential overpressurization of the RCS when operating in the water solid condition at low RCS temperature (Reference 4, Reference 17, and Section 4.2.)

The Pressurizer Heaters are employed if it is desired to maintain the RCS at full pressure. For the purposes of safe shutdown and cooldown in accordance with BTP RSB 5-1, the heaters are not needed. The pressurizer backup and control heaters are supplied power from emergency buses 16 and 14, respectively, and can be controlled either from the control room or locally. The heater groups working together automatically control RCS pressure at whatever setpoint is set into the pressurizer pressure controller.

3.3 Electrical Instrumentation and Power Systems

Table 3.3 provides a list of the instruments required to conduct a safe shutdown. The list includes those instruments which provide to the control room operator information from which the proper operation of all safe shutdown systems can be inferred. These are RCS pressure and temperature, pressurizer level and steam-generator level. Improper trending of these parameters would lead the operator to investigate the potential causes. Other instruments are listed in the table to provide the operator with 1) a direct check on safe shutdown system performance and 2) indication of actual or impending degradation of system performance. The list of instruments satisfies the requirements of BTP RSB 5-1 for safe shutdown. The DBE evaluations, which in many cases are not based on the same assumptions as this review, may determine that additional instrumentation is required to achieve and maintain a safe shutdown following a DBE.

The design of these instrumentation subsystems, as well as safe shutdown-related electrical control and power systems, will be evaluated in other topic reviews.

Offsite emergency power for Ginna Station is provided through a single 34.5-4.16 KV station auxiliary transformer. Therefore, applying the BTP 5-1 assumption of loss of onsite emergency power, i.e., loss of both diesel generators, the single failure of the auxiliary transformer would cause the loss of emergency power at Ginna. The acceptability of this design was reviewed during the Provisional Operating License review, and it was concluded that, because of the demonstrated high reliability of the type of transformers involved, the absence of a redundant transformer does not significantly affect the reliability of offsite power. A secondary source of offsite power can be made available via the unit auxiliary transformer by manually disconnecting flexible connections at the main generator terminals. This design is being reevaluated under SEP Topic VIII-1.A, "Potential Equipment Failures Associated with Degraded Grid Voltage."

Onsite power is furnished, when required, by two diesel engine generating sets. Either diesel can supply sufficient safety loads. The diesels and loads are divided on a split-bus arrangement. There is no automatic tie between the two buses. Both diesels are started by a "safety injection" signal, and each diesel is started by an undervoltage condition at either of its 480-volt buses. Each diesel can also be started manually from the control room or locally. The starting circuits are independent of each other, except that they both rely upon the station batteries for control current. This design is satisfactory since the complete failure of either battery will not prevent both diesels from being started automatically by the other battery. The diesel generators are located in separate rooms. The batteries are also in separate rooms.

The Ginna onsite and offsite electrical power systems will be further evaluated under several SEP topics.

The functional requirement to achieve cold shutdown conditions within a reasonable period of time is evaluated in Appendix A.

TABLE 3.1 CLASSIFICATION OF SHUTDOWN SYSTEMS R.E GINNA PLANT

Components/Subsystems	Quality Group R.G. 1.26	Quality Group Plant Design	Seismic R.G. 1.29	Seismic Plant Design	Remarks
Reactor Control and Protection System	NA*	--	Category I	Class I	*NA - not applicable
Auxiliary Feed System (AFS)					
Motor Driven Pumps (2)	ASME III Class 3	ASME VIII	Category I	Class I	
Piping and valves from pump discharge to valves 4000 C,D and including valves 4307 and 4310	ASME III Class 3	USAS B31.1 & nuclear code cases	Category I	Class I	
Turbine driven pump	ASME III Class 3	ASME VIII	Category I	Class I	
Piping and valves from pump discharge to valves 4003, 4004 and including valve CV-27	ASME III Class 3	USAS B31.1 & nuclear code cases	Category I	Class I	
Piping to suction of AFS pumps from Condensate Storage Tanks to valves 4014, 4017, and 4018	ASME III Class 3	USAS B31.1 & nuclear code cases	Category I	Class III	Main AFS water supply.
Piping to suction of AFS pumps from SWS and including valves 4014, 4017, and 4018	ASME III Class 3	USAS B31.1 & nuclear code cases	Category I	Class I	Backup AFS water supply.

TABLE 3.1 (Continued)

Components/Subsystems	Quality Group R.G. 1.26	Quality Group Plant Design	Seismic R.G. 1.29	Seismic Plant Design	Remarks
Turbine driven pump, lube oil tank, pump, and piping	ASME III Class 3	?	Category I	?	
Standby Auxiliary Feed System (SAFS)					Ref. RG&E letter of May 20, 1977
SAFS pumps (2)	ASME III Class 3	ASME III Class 3	Category I	Category I	
SAFS piping and valves from and including valves 9704 A, B to steam generators	ASME III Class 2	ASME III Class 2	Category I	Category I	
Condensate Supply Tank	API 650, AWWA-D100 or ANSI B96.1	AWWA-D100	Non-Category I	Category I	Nonnuclear safety tank. Failure of tank may affect SAFS pumps
Piping and valves to pump suctions from SWS to and including valves 9707A,B, 9720A,B and 9709A,B	ASME III Class 3	ASME III Class 3	Category I	Category I	
Piping and valves from pump discharge up to valves 9704A,B and including valves 9710A,B	ASME III Class 3	ASME III Class 3	Category I	Category I	
Other SAFS piping and valves	ANSI B31.1	ANSI B31.1 (1973)	Non-Category I	Non-Category I	

TABLE 3.1 (Continued)

Components/Subsystems	Quality Group R.G. 1.26	Quality Group Plant Design	Seismic R.G. 1.29	Seismic Plant Design	Remarks
Main Steam (MS) System					
MS Safety Valves	ASME III Class 2	USAS B31.1 & nuclear code cases	Category I	Class I	
MS Atmospheric Relief Valves	ASME III Class 2	USAS B31.1 & nuclear code cases	Category I	Class I	
Piping from steam generators to and including MS Isolation valves	ASME III Class 2	USAS B31.1 & nuclear code cases	Category I	Class I	
Piping and valves from MS line to auxiliary feed pump turbine	ASME III Class 3	USAS B31.1 & nuclear code cases	Category I	Class I	
Service Water System (SWS)					
SWS pumps (4)	ASME III Class 3	?	Category I	Class I	FDSAR page 9.6-6a
Piping and valves for containment cooling up to and including valves 4627, 4628, 4641, 4642, 4625, 4630, 4640, 4644, 4757, 4635, 4758, and 4636	ASME III Class 2	?	Category I	Class I	
Piping and valves excluding above and outside the turbine building including valves 4613, 4614 and supply lines to Auxiliary feed system	ASME III Class 3	?	Category I	Class I	Turbine building is Seismic Class II. SWS piping buried in yard is reinforced concrete type

TABLE 3.1 (Continued)

Components/Subsystems	Quality Group R.G. 1.26	Quality Group Plant Design	Seismic R.G. 1.29	Seismic Plant Design	Remarks
Chemical and Volume Control System					FDSAR Table 9.2-1
Charging pumps	ASME III Class 2	7	Category I	Class I	
Piping (loop B) letdown via regen. HX and letdown valves via letdown orifices to values 200 A, B, C	ASME III Class 1	USAS B31.1	Category I	Class I	Footnote 2, 50.55a
Regenerative Heat Exchanger	ASME III Class 1	ASME III Class C	Category I	Class I	
Piping (loop A) letdown line via excess letdown Hx to and including valve HCV-123	ASME III Class 1	USAS B31.1	Category I	Class I	
Piping and valves from pump discharge to containment isolation valve (normal and alternate charging lines)	ASME III Class 2	USAS B31.1 & nuclear code cases	Category I	Class I	
Piping from pump discharge via reactor coolant pumps and from HCV-123 to seal water Hx	ASME III Class 2	USAS B31.1	Category I	Class I	
Charging pump accumulator	ASME III Class 2	7	Category I	Class I	

TABLE 3.1 (Continued)

Components/Subsystems	Quality Group R.G. 1.26	Quality Group Plant Design	Seismic R.G. 1.29	Seismic Plant Design	Remarks
Excess Letdown Heat Exchanger (tube side)	ASME III Class 1	ASME III Class C	Category I	Class I	
(shell side)	ASME III Class 2	ASME VIII	Category I	Class I	
Reactor coolant filter	ASME III Class 2	ASME III Class C	Category I	Class I	
Seal water injection filters	ASME III Class 2	ASME III Class C	Category I	Class I	
Boric acid filter	ASME III Class 3	ASME III Class C	Category I	Class I	
Piping and valves downstream of letdown orifices to valve 371	ASME III Class 2	USAS B31.1	Category I	Class I	
Piping and valves from LCV 112C to charging pumps up to and including valves LCV 110B, 367, 271, 356, 352, 351, and the RWST	ASME III Class 2	USAS B31.1	Category I	Class I	
Pressurizer Subsystems					
Pressurizer	ASME III Class 1	ASME III, Class A	Category I	Class I	ASME Code editions prior to 1971 use the term Class A in lieu of Class 1

TABLE 3.1 (Continued)

Components/Subsystems	Quality Group R.G. 1.26	Quality Group Plant Design	Seismic R.G. 1.29	Seismic Plant Design	Remarks
Pressurizer Relief Valves	ASME III Class 1	?	Category I	Class I	
Pressurizer Safety Valves	ASME III Class 1	ASME III	Category I	Class I	
Pressurizer Heaters	NA	--	Category I	Class I	
Component Cooling Water (CCW)					
CCW pumps (2)	ASME III Class 3	?	Category I	Class I	
CCW heat exchangers	ASME III Class 3	ASME VIII	Category I	Class I	
Surge tank	ASME III Class 3		Category I	Class I	
CCW piping and valves	ASME III Class 3	USAS B31.1 & nuclear code cases	Category I	Class I	
Residual Heat Removal (RHR) System					
RHR pumps (2)	ASME III Class 2	?	Category I	Class I	RHR pumps provide LPSI and ECCS containment recirculation

TABLE 3.1 (Continued)

Components/Subsystems	Quality Group R.G. 1.26	Quality Group Plant Design	Seismic R.G. 1.29	Seismic Plant Design	Remarks
RHR heat exchangers (tube side)	ASME III Class 2	ASME III Class C	Category I	Class I	
(shell side)	ASME III Class 3	ASME VIII	Category I	Class I	
Piping and valves to RHR pump suction from RWST, containment sump, valve 701, and CVCS	ASME III Class 2	USAS B31.1 & nuclear code cases	Category I	Class I	
Piping and valves from RHR pump discharge to valves 1012 A,B and via RHR heat exchangers to RCS (valves 852 A,B, 720), CVCS, Sampling System, RWST, HPSI pump #1C, and recirculation line to RHR pumps	ASME III Class 2	USAS B31.1 & nuclear code cases	Category I	Class I	
Process Instrumentation and Controls	NA	--	Category I	Class I	For safe shutdown systems only; see section 3.3.
Emergency Power Supply System	NA	--	Category I	Class I	
Diesel generators			Category I	Class I	
DC power supply system			Category I	Class I	
Distribution lines, switchgear, control boards, motor control centers			Category I	Class I	

TABLE 3.2

FUNCTIONS FOR SHUTDOWN AND COOLDOWN

Function	Method
1. Control of Reactor Power	a. Boration 1. CVCS 2. High Pressure Safety Injection b. Control Rods 1. Controlled Rod Insertion 2. Reactor Trip
2. Core Heat Removal	a. Forced Circulation (reactor coolant pumps) b. Natural Circulation (using steam generators) c. Residual Heat Removal d. CVCS Letdown Heat Exchangers (CCW) e. Pressurizer Reliefs and Safety Injection
3. Steam Generator Heat Removal	a. Main Condenser (circulating water system) b. Atmospheric Dumps (manual actuation) c. Safety Valves d. Auxiliary Feed System Turbine e. Steam Generator Blowdown f. Water-Solid Steam Generator
4. Feedwater	a. Main Feedwater Pumps b. Steam- and Motor-Driven Auxiliary Feedwater Pumps c. Standby Auxiliary Feedwater Pumps
5. Primary System Control	a. CVCS b. Pressurizer Relief Valves

TABLE 3.3 LIST OF SAFE SHUTDOWN INSTRUMENTS

Component/System	Instrument		Instrument Location	Reference
Main Steam	Steam generator level LT & LI 460, 461 and 470, 471	LT LI	Inside Containment Control Room*	DWG. 33013-544, Refs. 4 and 15
	Steam Pressure PT & PI 468, 469, 478, 479	PT PI	Intermediate Building Control Room	DWG. 33013-534
Reactor Coolant	Pressurizer level LT & LI, 426, 427, 428, 433	LT LI	Inside Containment Control Room*	DWG. 33013-424, Refs. 6 and 15
	Pressurizer pressure PT & PI 449, 429, 430, 431	PT PI	Inside Containment Control Room*	DWG. 33013-424, Refs. 5 and 15
	RCS temperature TE & TI 409 A&B and 410 A&B	TE TI	Inside Containment Control Room	DWG. 33013-424, Refs. 6 and 15
Auxiliary Feed	AFWS flow FT 2001, 2002, 2023, 2024 FI 2021, 2022, 2023, 2024	FT FI	Intermed. Build. Control Room*	DWG 33013-544, Refs. 8 and 15
	SAFS flow FT & FI 4084, 4085	FT FI	Aux. Build. Addition Control Room*	DWG D-302-071-E, Refs. 5 and 15
Service Water	Pump discharge press. PT 2160 & 2161, PI 2160 & 2161	PT PI	Screen House Control Room	DWG 33013-529
Chemical and Volume Control	Charging flow FIT 128, FI 128	FIT FI	Auxiliary Build. Control Room	DWG 33013-433
	RWST level LT 920, LI 920	LT LI	Auxiliary Building Control Room	DWG 33013-425

*Also indicators are available at local shutdown panels

TABLE 3.3 LIST OF SAFE SHUTDOWN INSTRUMENTS

Component/System	Instrument	Instrument Location	Reference
Component Cooling Water	System flow FIT 619	FIT Auxiliary Build. Low flow alarm in control room	DWG 33013-436
	Surge tank level LIT 618	LIT Auxiliary Build. LI Control Room	DWG 33013-435
Residual Heat Removal	System flow FI 626, FI 626	FI Auxiliary Build. FI Control Room	DWG 33013-436
Diesel Generator	Generator output voltage and current	Control Room	
Emergency AC Power	480V Buses 14, 16, 17, 18, voltage indication	Control Room	
Emergency DC Power	125 VDC Buses 1 and 2 voltage indication	Control Room	

TABLE 3.4 SAFE SHUTDOWN SYSTEMS POWER SUPPLY AND LOCATION

System	Power Supply	Location
Reactor Protection, Reactor Breakers, Reactor bistables	DC power, Instrument buses	Control Room (289')
Main Steam		
Safety valves	-----	Intermediate Build. (278')
Isolation valves	air (fail closed)	Intermediate Build. (278')
Atmos. Dump valves	air or manual	Intermediate Build. (278')
Auxiliary Feed		
Motor driven pumps A, B	A-Bus 14, B-Bus 16	Intermediate Build. (253')
Turbine driven pump	Steam driven	Intermediate Build. (253')
Standby pumps C, D	C-Bus 14, D-Bus 16	Aux. Build. Addition (270')
Service Water pumps A, B, C, D	A,C-Bus 18 B,D-Bus 17	Screen House (253') Screen House (253')
Chemical and Volume Control pumps A, B, C	A-Bus 14 B, C-Bus 16	Auxiliary Build. (235') east
refueling water storage tank	-----	Auxiliary Build.
Component Cooling Water		
pumps A, B	A-Bus 14, B-Bus 16	Auxiliary Build. (271')
heat exchangers	-----	Auxiliary Build. (271')
Residual Heat Removal		
pumps A, B	A-Bus 14, B-Bus 16	Auxiliary Build. (219') RHR pit
heat exchangers	-----	Auxiliary Build. (219')
Diesel Generators		
1A	125VDC Control Power	Diesel room N side of turbine build. (253')
1B	125VDC Control Power	Diesel room N side of turbine build. (253')

TABLE 3.4 SAFE SHUTDOWN SYSTEMS POWER SUPPLY AND LOCATION

480 V Bus 14	Diesel 1A or offsite power	Auxiliary Build. (271')
480 V Bus 16	Diesel 1B or offsite power	Auxiliary Build. (263')
480 V Bus 17	Diesel 1B or offsite power	Screen House (253')
480 V Bus 18	Diesel 1A or offsite power	Screen House (253')
Instrument Buses 1A, 1B, 1C, 1D	1A-Inverter 1, 1B-480V MCC 1C-Inverter 2, 1D-480V MCC	Control Room (289')
Battery and Inverter 1A	----	Battery room (253')
Battery and Inverter 1B	----	Battery room (253')

4.0 SPECIFIC RESIDUAL HEAT REMOVAL AND OTHER REQUIREMENTS OF BRANCH TECHNICAL POSITION 5-1

BTP 5-1 contains the functional requirements discussed in Section 3.0 and also detailed requirements applicable to specific systems or areas of operation. Each of these specific requirements is presented below with a description of the applicable Ginna system or area of operation.

4.1 "B. RHR System Isolation Requirements

The RHR system shall satisfy the isolation requirements listed below.

1. The following shall be provided in the suction side of the RHR system to isolate it from the RCS.

   (a) Isolation shall be provided by at least two power-operated valves in series. The valve positions shall be indicated in the control room.

   (b) The valves shall have independent diverse interlocks to prevent the valves from being opened unless the RCS pressure is below the RHR system design pressure. Failure of a power supply shall not cause any valve to change position.

   (c) The valves shall have independent diverse interlocks to protect against one or both valves being open during an RCS increase above the design pressure of the RHR system.

2. One of the following shall be provided on the discharge side of the RHR system to isolate it from the RCS:

   (a) The valves, position indicators, and interlocks described in item 1(a)-(c).

   (b) One or more check valves in series with a normally closed power-operated valve. The power-operated valve position shall be indicated in the control room. If the RHR system discharge line is used for an ECCS function the power-operated valve is to be opened upon receipt of a safety injection signal once the reactor coolant pressure has decreased below the ECCS design pressure.

(c) Three check valves in series, or

(d) Two check valves in series, provided that there are design provisions to permit periodic testing of the check valves for leaktightness and the testing is performed at least annually."

The RHR suction and discharge valves connecting this system to the primary coolant system are shown on Figure 9.3-1 of the R. E. Ginna FSAR. The reactor coolant system suction supply to the RHR pumps is from the hot leg of loop A through motor-operated valves MOV 700 and MOV 701 in series. The RHR pump discharge return to the loop B cold leg of the reactor coolant system is through two series motor-operated valves, MOV 720 and MOV 721. There are no check valves in series with MOV 720 and MOV 721.

Permissive interlocks required to open the four RHR system isolation valves are listed below.

MOV 700	(1)	Reactor coolant system pressure must be less than 410 psig
	(2)	RHR suction valves MOV 850A and MOV 850B from the containment sump must be closed
MOV 701	(1)	RHR suction valves MOV 850A and MOV 850B from the containment sump must be closed
	(2)	The valve is operated by a key switch
MOV 720	(1)	No interlocks exist but the valve is operated by a key switch
MOV 721	(1)	Reactor coolant system pressure must be less than 410 psig

No interlocks are associated with valve closure. There are no automatic functions which close the valves and no alarms generated by the valves (Reference 5). The valves fail "as is" upon loss of power supply and have remote position indication in the control room.

The RHR system discharge line is not used for an ECCS function that would require MOV 720 or MOV 721 to open; however, a branch of the RHR discharge line provides low pressure safety injection (LPSI) to the reactor vessel via parallel lines with one normally closed motor-operated valve and one check valve in each line. The check valves are periodically tested. The motor-operated valve position indication is provided in the control room and these valves receive an open signal coincident with the safety injection (SI) signal.

Based on the above description, the RHR system deviates from these BTP provisions:

(a) The power-operated valves in the LPSI lines open on an SI signal before RCS pressure drops below RHR design pressure.

(b) The RHR discharge and suction isolation valves do not have independent diverse interlocks to prevent opening the valves until RCS pressure is below 410 psig. Only the inboard valves (700, 721) have this interlock. The outboard valves (701, 720) are manually controlled with key-locked switches. By procedure, MOV 701 and MOV 720 are not opened until RCS pressure is less than 410 psig.

(c) The RHR isolation valves have no interlock feature to close them when RCS pressure increases above the design RHR pressure.

The staff has concluded that the deviation regarding the independent, diverse interlocks to prevent opening of the RHR isolation valves until pressure is below 410 psig is acceptable. The RHR isolation valves are designed such that they are physically unable to open against a differential pressure of greater than 500 psi. The inboard isolation valves are provided with a pressure interlock. By administrative procedure, the RHR valves are key-locked closed, with power removed. In addition, a relief valve (RV203), set at 600 psig, is available. The staff therefore has concluded that the probability of an intersystem LOCA is acceptably low.

The deviation regarding the LPSI isolation valve is considered acceptable since the check valve testing provides sufficient assurance that these valves will perform their isolation function until RCS pressure decreases below RHR pressure. The staff's position on these deviations is given in Section 5.2.

The deviation regarding lack of automatic closure for the RHR isolation valves is acceptable based on the administrative controls which the licensee provides for the operation of these valves, coupled with the RHR system high pressure alarm at 550 psig and the RCS interlock pressure alarm at 410 psig (Reference 5). These alarms provide adequate assurance that the operator action required by procedure will be taken to shut the isolation valves when RCS pressure is increasing towards the RHR design pressure. (See the following discussion of BTP provision C.1, "Pressure Relief Requirements.")

4.2 "C. Pressure Relief Requirements

The RHR system shall satisfy the pressure relief requirements listed below.

1. To protect the RHR system against accidental overpressurization when it is in operation (not isolated from the RCS), pressure relief in the RHR system shall be provided with relieving capacity in accordance with the ASME Boiler and Pressure Vessel Code. The most limiting pressure transient during the plant operating condition when the RHR system is not isolated from the RCS shall be considered when selecting the pressure relieving capacity of the RHR system. For example, during shutdown cooling in a PWR with no steam bubble in the pressurizer, inadvertent operation of an additional charging pump or inadvertent opening of an ECCS accumulator valve should be considered in selection of the design basis.

The RHR relief valve has a setpoint of 600 psig and a capacity of 70,000 lb/hr. The RHR system is provided with a 550 psig high pressure alarm and a reactor coolant system interlock pressure alarm at 410 psig. The RHR system is connected to the loop A hot leg on the suction side and the loop B cold leg on the discharge side. The design pressure and temperature of the RHRS are 600 psig and 400°F. The design basis with regard to overpressure protection for Ginna Station's RHRS is to prevent opening of the RHR isolation valves when RCS pressure exceeds 450 psig and to provide relief capacity sufficient to accommodate thermal expansion of water in the RHR and/or leakage past the system isolation valves.

An analysis of incidents which might lead to overpressurizing the RHR system was performed (Reference 5). Three events were considered in the analysis:

(a) With RCS in solid condition and RHR and charging pumps operating, the letdown line from the RCS is isolated.

(b) During cooldown using two RHR trains, one RHR train suffers a failure at a time when the core heat generation rate exceeds the heat removal capability of one train.

(c) Pressurizer heaters are energized with RHR in operation and RCS solid.

The results of these analyses show that the RHR system is provided adequate relief capacity provided certain procedural changes are implemented. These changes have been implemented in the licensee's operating procedures.

Overpressure transients more severe than the three listed above have been analyzed by the licensee in conjunction with the reactor vessel overpressurization protection system (OPS) (Reference 4). To successfully mitigate these worst case transients, the licensee has modified the pressurizer power operated relief valve (PORVs) to provide a low pressure relief setpoint of 435 psig during plant cold shutdown conditions and has implemented several administrative controls changes. The PORVs also provide overpressure protection for the RHR system when the RHR is aligned to the RCS for shutdown cooling.

The staff has evaluated the effects of the worst case mass and heat input events to establish the capability of the OPS and RHR relief to prevent RHR overpressurization. For the mass input case presented in Reference 4, the OPS alone prevents pressure from exceeding the RHR design pressure. For the heat input case, the Reference 4 data was extrapolated to include a 50°F steam generator to RCS temperature difference at an RCS temperature of 300°F. (The data in Reference 4 only applied to heat input transients at RCS temperatures from 180°F to 250°F.) 300°F was chosen because, this is the maximum temperature for which the steam generator to RCS temperature difference is 50°F based on RHR initiation at 350°F. The staff determined that pressure transients, at an RCS temperature of 300°F which would result from heat addition, would not exceed 110% of RHR design pressure even assuming the failure of one PORV. No credit is taken for action of relief valve RV-203. The staff then considered the potential for initiating a heat input transient at Ginna when RCS temperature is between 300°F and 350°F. For a heat input transient to occur, the heat from the steam generators must be rapidly transferred to a cooler, water-solid RCS. The means of rapid heat transfer is forced convection caused by a reactor coolant pump start. In its review of overpressurization transients, the staff considered steam generator to RCS temperature differences in excess of 50°F to be unlikely occurrences. The administrative measures proposed by the licensee to reduce the probability of heat input transient were to (1) require an acceptable RCS temperature profile prior to reactor coolant pump startup with a water-solid RCS, (2) require one coolant pump to be run until RCS temperature is less than or equal to 150°F, and (3) minimize plant operation in a water-solid condition. Although items (1) and (3), above, would not necessarily preclude a heat addition event, item (2) would. Also, the staff examined the potential for initiating a heat input event during plant cooldown, which is the time that steam generator temperature may exceed RCS temperature with RCS temperature above 300°F. The licensee initiates RHR cooling at 350°F after cooling down to that point with the steam generators. Continuing the cooldown with the RHR system and with the reactor coolant pumps secured (in violation of procedures), would result in the 50°F difference being fully developed at an RCS temperature of 300°F. As noted before, a heat input event at this temperature would not result in RHR overpressurization even with an assumed single failure.

Based on the above discussion, we conclude that the OPS and RHR relief provide sufficient RHR overpressure protection for RCS temperatures of 300°F or less and that the licensee's procedures acceptably minimize the likelihood of a heat addition overpressure transient at RCS temperatures above 300°F. Therefore, the OPS and the RHR relief meet the pressure relief requirements of the BTP. The OPS and related Technical Specifications were approved by the staff in Reference 17.

By procedure, the OPS is enabled at the same time as RHR cooling is initiated during plant cooldown, so the RHR system is afforded the additional overpressure protection of the OPS. The licensee will be required to incorporate, into the plant Technical Specifications, a requirement for enabling of the OPS whenever RHR cooling is in progress to assure this safety margin is maintained for the life of the plant. The licensee has agreed to incorporate this change (Reference 20).

4.2.1 "2. Fluid discharged through the RHR system pressure relief valves must be collected and contained such that a stuck open relief valve will not:

"(a) Result in flooding of any safety-related equipment.

"(b) Reduce the capability of the ECCS below that needed to mitigate the consequences of a postulated LOCA.

"(c) Result in a nonisolatable situation in which the water provided to the RCS to maintain the core in a safe condition is discharged outside of the containment."

Fluid discharged through the 2-inch RHR relief valve (RV203) is directed to the pressure relief tank (PRT) inside the reactor containment. The PRT has a rupture disc which is designed to rupture at 100 psig and allow the contents of the tank to overflow to the containment sump, where it would be available for recirculation. Should flow from a stuck RHR relief valve cause the rupture disc to rupture, the consequences to safety-related equipment would be less severe than the consequences of post-LOCA containment flooding which has been previously analyzed and found acceptable (Reference 6).

If RV203 were to stick open in a post-LOCA scenario, RHR flow to the RCS for both low head recirculation and low head safety injection modes would be affected. This is because a flow path would exist from the RHR system to RV203 via valves HCV-133 and 703 in either of these RHR operating modes. HCV-133 fails shut following loss of instrument air on containment isolation following a LOCA, but a flow path would still exist to RV203 via the 3/4-inch locked open manual valve 703. The affect of this flow diversion would not reduce the capability of the ECCS below that needed to mitigate the consequences of a postulated LOCA. This is because the design flow rate through RV203 (70,000 lb/hr, which is a conservative number in this case since HCV-133 is shut) is much less than the flow rate of an RHR pump in the low pressure safety injection (LPSI) mode (776,000 lb/hr). Each RHR pump has the capacity to provide 100% of the required LPSI flow. Therefore, the leakage through RV203 would not be as severe an event as the loss of an RHR pump which has been postulated as a single failure in the ECCS analysis.

4.2.2 "3. If interlocks are provided to automatically close the isolation valves when the RCS pressure exceeds the RHR system design pressure, adequate relief capacity shall be provided during the time period while the valves are closing."

As noted above, these interlocks are not provided. However, the procedures for coordination of the overpressure protection and RHR systems as described above provide adequate relief capacity to prevent the RCS pressure from exceeding RHR design pressure.

4.3 "D. Pump Protection Requirements

"The design and operating procedures of any RHR system shall have provisions to prevent damage to the RHR system pumps due to overheating, cavitation or loss of adequate pump suction fluid."

The features designed into the Ginna RHR system to prevent damage to the system centrifugal pumps are provision for pump cooling, a pump mini-flow recirculation flow path, and system design to prevent loss of net positive suction head (NPSH).

The CCW system provides cooling for the RHR pumps to prevent damage from overheating. The RHR pumps are provided with a recirculation line to recycle a portion of the pump discharge fluid to the pump suction. This prevents overheating caused by operating the pumps under no flow conditions. NPSH calculations were performed for the RHR pumps by the licensee. The RHR operating modes evaluated were normal plant shutdown cooling, low pressure safety injection, and post-LOCA recirculation. Recirculation operation developed the most limiting NPSH requirements, but the calculations indicated a 43% NPSH margin is available during recirculation (Reference 7, page 6.2-37). The RHR NPSH requirements will be reevaluated during the SEP under Topic VI-7.E, "ECCS Sump Design and Test for Recirculation Mode Effectiveness."

The above protection features provide adequate protection to prevent RHR pump damage.

4.4 "E. Test Requirements

> "The isolation valve operability and interlock circuits must be designed so as to permit online testing when operating in the RHR mode. Testability shall meet the requirements of IEEE Standard 338 and Regulatory Guide 1.22. The preoperational and initial startup test program shall be in conformance with Regulatory Guide 1.68. The programs for PWRs shall include tests with supporting analysis to (a) confirm that adequate mixing of borated water added prior to or during cooldown can be achieved under natural circulation conditions and permit estimation of the times required to achieve such mixing, and (b) confirm that the cooldown under natural circulation

conditions can be achieved within the limits specified in the emergency operating procedures. Comparison with performance of previously tested plants of similar design may be substituted for these tests."

The RHR isolation valve operability and interlocks cannot be tested during the RHR cooling mode of operation. This test requirement is not applicable to the Ginna facility, since the installed interlocks function only when the RHR isolation valves are shut.

Regulatory Guide 1.68 was not in existance when the Ginna preoperational and initial startup testing was accomplished. However, tests have been performed to confirm that cooldown under natural circulation can be achieved (Reference 8). The core flow rates achieved under natural circulation were more than adequate for decay heat removal. The calculated core flow at approximately 2% reactor power was 4.2% of nominal full power flow. At approximately 4% reactor power, calculated core flow was 5.2% of nominal. Flow rates of this magnitude should provide adequate mixing of boron added to the RCS during cooldown. An incident at Ginna Station on July 5, 1970, provides further indication that natural circulation will provide uniform mixing of boron in the RCS (Reference 9). During that incident, while steam system maintenance was in progress with no RCPs operating, natural circulation was indicated by incore thermocouple readings. While the RCPs were secured, 1365 gallons of water were added to the RCS to dilute the boron concentration. When an RCP was restarted, reactor power, which was being maintained at a low power level corresponding to 10^{-7} amps on the intermediate range channel, did not change. This indicates that the natural circulation flow had uniformly mixed the boron throughout the RCS.

4.5 "F. Operational Procedures

> "The operational procedures for bringing the plant from normal operating power to cold shutdown shall be in conformance with Regulatory Guide 1.33. For pressurized water reactors, the operational procedures shall include specific procedures and information required for cooldown under natural circulation conditions."

Operational procedures reviewed in this comparison of the Ginna Station to BTP RSB 5-1 are discussed in Section 2.0. All of the procedures required the use of nonsafety-grade equipment for portions of the shutdown operation. The licensee performed a review of a plant shutdown utilizing safety-grade equipment only; this procedure would require remote hand operation of certain air-operated valves because the control air system is not safety-grade. The procedures for shutdown and cooldown should provide instructions as to how safety-grade equipment could be used to perform the cooldown. No procedure exists for proceeding to cold shutdown conditions from outside the control room. The need for procedures for these evolutions stems from the provisions of BTP RSB 5-1 and SEP Topic VII-3 to provide assurance that the capability for decay heat removal with safety-grade equipment exists. The staff will consider requiring the licensee to develop these procedures during the integrated SEP assessment of the Ginna plant. We conclude that the procedures for safe shutdown and cooldown at Ginna are in conformance with Regulatory Guide 1.33. The plant operating procedures also include a procedure for cooldown using natural circulation.

4.6 "G. Auxiliary Feedwater Supply

"The seismic Category I water supply for the auxiliary feedwater system for a PWR shall have sufficient inventory to permit operation at hot shutdown for at least four hours, followed by cooldown to the conditions permitting operation of the RHR system. The inventory needed for cooldown shall be based on the longest cooldown time needed with either only onsite or only offsite power available with an assumed single failure."

The Category I water supply for the auxiliary feed system (AFS) is the service water system (SWS). The SWS, which must be manually aligned to the AFS system, receives its water supply from Lake Ontario via the seismic Class I screen house. This source of water, which has never been interrupted in the nine years of plant operation, provides sufficient AFS water supply with an assumed single failure regardless of the loss of offsite or onsite power.

The SEP will reexamine the adequacy of the screen house to provide water during emergency shutdown and maintenance of safe shutdown during resolution of SEP topics on seismic design and flooding.

The SEP has reevaluated the capability of the Ginna plant to achieve cold shutdown conditions within a reasonable period of time in Appendix A.

5.0 RESOLUTION OF SEP TOPICS

The SEP topics associated with safe shutdown have been identified in the INTRODUCTION to this assessment. The following is a discussion of how the Ginna Station meets the safety objectives of these topics.

5.1 Topic V-10.B RHR System Reliability

The safety objective for this topic is to ensure reliable plant shutdown capability using safety-grade equipment using the guidelines of SRP Section 5.4.7, Regulatory Guide 1.139, and BTP RSB 5-1. The Ginna Station systems have been compared with these criteria, and the results of these comparisons are discussed in Sections 3.0 and 4.0 of this assessment. Based on these discussions, we have concluded that the Ginna systems fulfill the topic safety objectives except for the requirement for procedures to shutdown and cooldown using safety-grade systems.

The licensee will be required to ensure that their operating procedures contain sufficient information to enable plant operators to perform required functions, such as decay heat removal, with safety-grade systems.

5.2 Topic V-11.A Requirements for Isolation of High and Low Pressure Systems

The safety objective of this topic is to assure adequate measures are taken to protect low pressure systems connected to the primary system from being subjected to excessive pressure which could cause failures and in some cases potentially cause a LOCA outside of containment.

This topic is assessed in this report only with regard to the isolation requirements of the RHR system from the RCS. As discussed in Sections 4.1 and 4.2, adequate overpressure protection for the RHR system will exist when the plant technical specifications are modified to require enabling the overpressure protection system whenever RHR cooling is in progress. The licensee agreed to this change in a letter dated January 13, 1981.

5.3 Topic V-11.B RHR Interlock Requirements

The safety objective of this topic is identical to that of Topic V-11.A. The staff conclusion regarding the Ginna RHR interlocks, as discussed in Section 4.1, is that adequate interlocks exist subject to completion of the above modification.

In addition to these requirements, and as a matter to be resolved separately from the SEP, the NRC staff has determined that certain isolation valve configurations in systems connecting the high-pressure Primary Coolant System (PCS) to lower-pressure systems extending outside containment are potentially significant contributors to an intersystem loss-of-coolant accident (LOCA). Such configurations have been found to represent a significant factor in the risk computed for core melt accidents (WASH-1400, Event V). The sequence of events leading to the core melt is initiated by the failure of two in-series check valves to function as a pressure isolation barrier between the high-pressure PCS and a lower-pressure system extending beyond containment. This causes an overpressurization and rupture of the low-pressure system, which result in a LOCA that bypasses containment.

The NRC has determined that the probability of failure of these check valves as a pressure isolation barrier can be significantly reduced if the pressure at each valve is continuously monitored or if each valve is periodically inspected by leakage testing, ultrasonic examination, or radiographic inspection. NRC has established a program to provide increased assurance that such multiple isolation barriers are in place in all operating Light Water Reactor plants. This program has been designated Multiplant Action Item MP 3-45.

In a generic letter of February 23, 1980 (Reference 18), NRC requested all licensees to identify susceptible valve configurations which may exist in any of their plant systems communicating with the PCS. For plants in which valve configurations of concern were found to exist, licensees were further requested to indicate: 1) Whether, to ensure integrity, continuous surveillance or periodic testing was currently being conducted, 2) whether any valves of concern were known to lack integrity, and 3) whether plant procedures should be revised or plant modifications be made to increase reliability.

Ginna is one of those plants identified as being susceptible to the potential failure, since the high-head safety injection system is protected by two check valves and one motor-operated valve in series, and the low-head safety system is protected by one check valve in series with one motor-operated valve. By NRC order dated April 20, 1981, (Reference 19) the Ginna Technical Specifications were modified to include check valves in the cold leg high-head injection system and those in the low head safety injection system in a periodic check valve pressure integrity test program.

5.4 Topic VII-3 Systems Required for Safe Shutdown

The safety objectives of this topic are:

A. To assure the design adequacy of the safe shutdown system to (1) initiate automatically the operation of appropriate systems, including the reactivity control systems, such that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences or postulated accidents, and (2) initiate the operation of systems and components required to bring the plant to a safe shutdown.

B. To assure that the required systems and equipment, including necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown, are located at appropriate locations outside the control room and have a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

C. To assure that only safety-grade equipment is required for a PWR plant to bring the reactor coolant system from a high pressure condition to a low pressure cooling condition.

Safety objective A(1) will be resolved in the SEP design basis event reviews. These reviews will determine the acceptability of the plant response, including automatic initiation of safe shutdown related systems, to various design basis events, i.e., accidents and transients (Reference 10).

Objective A(2) relates to availability in the control room of the control and instrumentation systems needed to initiate the operation of the safe shutdown systems and assures that the control and instrumentation systems in the control room are capable of following the plant shutdown from its initiation to its conclusion at cold shutdown conditions. The ability of the Ginna Station to fulfill objective A(2) is discussed in the preceding sections of this report. Based on these discussions, we conclude that safety objective A(2) is met by the safe shutdown system at the Ginna Station subject to the findings of related SEP electrical, instrumentation and control topic reviews.

Safety objective B requires the capability to shutdown to both hot shutdown and cold shutdown conditions using systems, instrumentation and controls located outside the control room.

The Ginna Station has a procedure, "Control Room Inaccessibility," for shutdown outside the control room. The procedure contains the assignments of operating personnel to the control stations near the auxiliary feedwater pumps, in the charging pump room and the boric acid storage tank area. The procedure contains the necessary steps to take the plant to the hot shutdown condition using manual control of the auxiliary feedwater pumps for steam generator level control, the backup heaters for pressurizer pressure control, and the charging pumps and boric acid transfer pumps for primary coolant inventory and reactivity control. The communications between the various remote stations has redundant power supplies from the diesel generators and the plant batteries. The following instrumentation is at the remote stations:

A. Charging pump speed
B. Steam generator level
C. Steam generator pressure
D. Auxiliary feedwater pump flow

E. Pressurizer level

F. Pressurizer pressure

No procedure exists for proceeding to cold shutdown conditions from remote (outside the control room) stations. However, all the required systems and components could be operated at local stations throughout the plant. The required instrumentation, in addition to that listed above, is an indication of RCS temperature. This can be calculated from steam generator pressure since the steam generator is at saturated conditions.

Additional systems required for cold shutdown beyond those used for normal operation or hot shutdown are the RHR system and the steam generator atmospheric dump valves. The atmospheric dumps are manually operable from the intermediate building and the RHR pumps can be started from their motor control centers. All required valves are manual or motor-operated with manual override except for the air-operated pressurizer spray valves (normal and auxiliary). Therefore, depressurization of the RCS would be limited to the depressurization rate caused by ambient heat losses from the pressurizer and by the makeup water charged to the RCS to account for coolant shrinkage during cooldown. The depressurization of the RCS in this manner to the pressure required for RHR initiation has been estimated to require approximately 48 hours. The SI accumulators can be isolated and RCS sampling can be accomplished outside the control room also.

Based on the above discussion, we conclude that the Ginna facility meets safety objective B of Topic VII-3, provided an operating procedure is developed for conducting a plant cooldown from hot shutdown to cold shutdown from outside the control room. The staff considers that this requirement can be implemented in conjunction with Fire Protection requirements.

The adequacy of the safety-grade classification of safe shutdown systems at Ginna, to show conformance with safety objective C, will be completed in part under SEP Topic III-1, "Classification of Structures, Components and Systems (Seismic and Quality)," and in part under the design basis event reviews. Table 3.1 of this report will be used as input to Topic III-1.

5.5 Topic X Auxiliary Feed System (AFS)

The safety objective for this topic is to assure the AFS can provide adequate cooling water for decay heat removal in the event of loss of all main feedwater using the guidelines of SRP Section 10.4.9 and BTP ASB 10-1.

The Ginna AFS and SAFS are described in Section 3.2. These systems have been compared with SRP Section 10.4.9 and BTP ASB 10-1 with the following conclusions:

a. The Ginna Station, including the AFS, will be reevaluated during the SEP with regard to internally- and externally-generated missiles, seismic design requirements, and flood and tornado protection. The SAFS will be reevaluated for internal and external missiles, seismic design requirements, and flood and tornado protection.

b. The AFS and SAFS conform to GDC 19, "Control Room," GDC 44, "Cooling Water," GDC 45, "Inspection of Cooling Water Systems," GDC 46, "Testing of Cooling Water Systems," and Regulatory Guide 1.62, "Manual Initiation of Protective Actions." GDC 5, "Sharing of Structures, Systems and Components," is not applicable.

c. Waterhammer in the feed system at Ginna is discussed under SEP Topic V-13, "Waterhammer."

d. There is no provision for either the AFS or SAFS to automatically terminate flow to a depressurized steam generator and automatically provide flow to the intact steam generator. This is accomplished by the control room operator. The effect of the lack of automatic switching of flow to the intact steam generator will be assessed in the main steam line break evaluation for Ginna.

e. The Technical Specifications for the AFS will be reevaluated against current requirements under SEP Topic XVI, "Technical Specifications."

f. AFS and SAFS electrical power, instrumentation and control system design will be evaluated under other topics in the SEP as well as under TMI item II.E.1.

g. The possibility of a seismic event (1) severing the CST supply lines, and (2) initiating events which would cause the automatic start and destruction of the AFS pumps because of loss of suction fluid was considered. The potential loss of the AFS pumps is considered acceptable because of the availability of the backup SAFS pumps.

With the exception of above items a., d., e., and f., which will be further evaluated, the AFS and SAFS fulfill the safety objective of Topic X. The TMI Task Action Plan II.E.1 will further address the auxiliary feedwater system design.

6.0 REFERENCES

1. Summary of 109th ACRS meeting, May 8-10, 1969, dated 5/22/69, revised 6/9/69.
2. NRC letter, K. Goller to E. Nelson, dated 10/2/74.
3. RG&E letter, K. Amish to J. O'Leary, dated 5/24/74.
4. RG&E letter, L. White to A. Schwencer, dated 7/29/77.
5. RG&E letter, L. White to A. Schwencer, dated 2/24/77, subject: Reactor Vessel Overpressurization - R. E. Ginna Nuclear Power Plant.
6. Memorandum, V. Stello to K. Goller, dated 10/8/75.
7. Robert Emmett Ginna Nuclear Power Plant, Unit No. 1, Final Facility Description and Safety Analysis Report.
8. RG&E letter, LeBoeuf, Lamb, Lerby & MacRae, to AEC, dated 2/2/71.
9. RG&E letter, K. Amish to P. Morris, dated 7/15/70.
10. Systematic Evaluation Program, Status Summary Report, NUREG-0485.
11. Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum from Director, NRR, to NRR Staff, NUREG-0138, November 1976.
12. RG&E letter, J. E. Maier to D. M. Crutchfield, dated March 19, 1981.
13. RG&E letter, L. White to D. Ziemann, dated 7/27/78.
14. Branch Technical Position, MEB 3-1 appended to Standard Review Plan 3.6.2.
15. RG&E letter, K. Amish to A Giambusso, dated November 1, 1973, forwarding Effects of Pipe Breaks Outside Containment Report.
16. NRC letter, D. Ziemann to L. White, dated August 24, 1979, forwarding Amendment No. 29 to the Ginna Operating License.

17. NRC letter, D. Ziemann to L. White, dated April 18, 1979, forwarding Amendment No. 26 to the Ginna Operating License.

18. NRC letter, D. M. Crutchfield to J. E. Maier (RG&E) dated, February 23, 1980.

19. NRC letter, D. M. Crutchfield to J. E. Maier (RG&E), dated April 20, 1981.

20. RGE letter, J. E. Maier to D. M. Crutchfield, dated January 13, 1981.

APPENDIX A

SAFE SHUTDOWN WATER REQUIREMENTS

Introduction

Standard Review Plan (SRP) 5.4.7, "Residual Heat Removal (RHR) System" and Branch Technical Position (BTP) RSB 5-1, Rev. 1, "Design Requirements of the Residual Heat Removal System" are the current criteria used in the Systematic Evaluation Program (SEP) evaluation of systems required for safe shutdown. BTP RSB 5-1 Section A.4 states that the safe shutdown systems shall be capable of bringing the reactor to a cold shutdown condition, with only offsite or onsite power available, within a reasonable period of time following shutdown, assuming the most limiting single failure. BTP RSB 5-1 Section G, which applies specifically to the amount of auxiliary feed system (AFS) water of a pressurized water reactor available for steam generator feeding, requires the seismic Category I water supply for the AFS to have sufficient inventory to permit operation at hot shutdown for at least four hours, followed by cooldown to the conditions permitting operation of the RHR system. The inventory needed for cooldown shall be based on the longest cooldown time needed with either only onsite or only offsite power available with an assumed single failure. A reasonable period of time to achieve cold shutdown conditions, as stated in SRP 5.4.7 Section III.3, is 36 hours. For a reactor plant cooldown, the transfer of heat from the plant to the environs is accomplished by using water as the heat transfer medium. Two modes of heat removal are available. The first mode involves the use of reactor plant heat to boil water with the resulting steam vented to the atmosphere. The water for this process is typically demineralized, "pure" water stored onsite and, therefore, is available only in limited quantities. The systems designed to use this type of heat removal process (boiloff) are the steam generators for a pressurized water reactor (PWR) or the emergency (isolation) condenser for a boiling water reactor (BWR). The second heat removal mode involves the use of power operated relief valves to remove heat in the form of steam energy directly from the reactor coolant system. Since it is not acceptable to vent the reactor coolant system directly to the atmosphere following certain accidents, the steam is typically vented to the containment building from where it is removed by containment heat removal systems. The containment heat removal systems are in turn cooled by a cooling water system which transfers the heat to an ultimate heat sink - usually a river, lake, or ocean. When using the blowdown mode, reactor coolant system makeup water must be continuously supplied to keep the reactor core covered with coolant as blowdown reduces the coolant inventory. Systems employing the blowdown heat removal mode have been designed into or backfitted onto most BWR's. The efficacy of the blowdown mode for PWR's has received increased staff attention since the Three Mile Island Unit 2 accident in March 1979. Additional studies of the viability of this mode for PWR's are in progress or planned.

This evaluation of cooling water requirements for safe shutdown (and cooldown) is based on the use of the systems identified in the SEP Review of Safe Shutdown Systems which has been completed for each SEP facility. The Review of Safe Shutdown Systems used SRP 5.4.7 and BTP RSB 5-1 as a review basis. It

It should be noted that the SEP Design Basis Events (DBE) reviews, which are currently in progress, may require the use of systems other than those which are evaluated in this report for reactor plant shutdown and cooldown. In those cases, the water requirements for safe shutdown will have to be evaluated using the assumptions of the DBE review.

Discussion

The requirement that a plant achieve cold shutdown conditions within approximately 36 hours, as profferred in BTP RSB 5-1 and SRP 5.4.7, is based mainly on the fact that the amount of onsite - stored water for the AFS of a PWR is limited, and it is desirable to be able to place the RHR system in operation and transfer the plant heat to an ultimate heat sink prior to the exhaustion of the onsite -stored AFS water supply. Remaining in a hot shutdown condition, with reactor coolant system temperature and pressure in excess of RHR initiation limits, requires the continued expenditure of pure water via the boiloff mode to remove reactor core decay heat. A BWR relying on the emergency condenser system for cooldown would also be susceptible to the potential exhaustion of onsite - stored pure water.

Should the onsite-stored water supply at a plant be expended, the capability usually exists to use raw water from a river, lake, or ocean for example, to supply the boiloff systems. However, use of raw water can lead to the degradation, through corrosion, of the boiloff system materials, i.e., steam generator and emergency condenser tubes. This degradation can occur rapidly even if fresh water makeup is used. If seawater were used, chloride stress corrosion cracking of the tubes could occur well within one week.* If raw fresh water were used, caustic stress corrosion cracking of tube materials could occur under certain operating conditions in less than 72 hours for both stainless steel and inconel tube materials through NaOH concentration.* A plant cooldown and depressurization would help reduce the rate of tube cracking by reducing the stresses in the tube materials. Also, the leakage rate of reactor coolant through potential cracks in the tubes would be reduced if the plant were in a cool, depressurized state.

The original design criteria for the SEP facilities did not require the ability to achieve cold shutdown conditions. For these plants, and for the majority of operating plants, safe shutdown was defined as hot shutdown. Therefore, the design of the systems used to achieve cold shutdown was determined by the reactor plant vendor and was not based on any safety concern. Cold shutdown for a PWR, as shown in BTP RSB 5-1, is defined as the reactor shut down with average coolant temperature $\leq$ 200°F. Therefore, an RHR and supporting systems, in addition to the steam generators, are needed to get down to 200 degrees Fahrenheit.

Evaluation

Table 1 provides plant specific data and assumptions used in the staff calculation of safe shutdown water requirements for the Ginna nuclear plant.

*van Rooyen, Daniel and Martin W. Kendig, "Impure Water in Steam Generators and Isolation Generators," BNL-NUREG-28147, Informal Report, June 1980.

Table 2 provides the results of the calculation. The phases of the cooldown from reactor trip to RHR initiation are shown on Figure 1.

At phase 1, the plant is heating up to the steam generator safety valve setpoint (562°F) because the main condenser is no longer available for heat removal (offsite power is lost), and the air-operated steam generator atmospheric dump valves do not open automatically because the compressed air systems are not assumed to be available. One of eight safety valves is required to remove core heat a few seconds after reactor trip.

After one or more safety valve lifts, an auxiliary feed system (AFS) pump is required to makeup the inventory lost from the steam generator(s) through the safety valve(s). One AFS pump (200 gpm) is sufficient to supply makeup requirements at approximately 10 minutes after reactor trip. The amount of AFS water consumed during phase 2 is greater than the technical specification minimum requirements for condensate storage tank inventory (15,000 gal.). Therefore, during phase 2, an operator must shift AFS pump suction to the service water system (SWS) to continue steam generator makeup. The condensate storage tank and connected piping are also not qualified for a seismic event so the shift to the SWS for AFS makeup may have to be completed quickly following an earthquake. During all phases of the cooldown, the Chemical and Volume Control System (CVCS) must be available to supply makeup to the reactor coolant system (RCS) to replace normal RCS leakage and to accomodate RCS coolant shrink and to add boron during cooldown.

Phase 2 is terminated by the commencement of a plant cooldown. This is accomplished by manually opening one or both atmospheric dump valves. In Table 2, it can be seen that one dump valve can reduce RCS temperature below the residual heat removal (RHR) system initiation temperature of 350°F within 10 hours. RCS pressure must be reduced to less than 410 psig before the RHR system isolation valves can be opened. Pressure reduction is normally accomplished using the pressurizer sprays which add colder water to the steam volume of the pressurizer. The normal pressurizer spray is assumed inoperable because it depends on RCS pump head, and the pumps require offsite power. The alternate spray line, which is supplied by the CVCS pumps, has an air-operated valve which fails shut on loss of air; therefore normal and alternate pressurizer sprays are not operable. The licensee performed a calculation to determine the ability of the plant to depressurize without sprays. The licensee estimated that the RCS pressure would be reduced to the RHR initiation pressure in approximately 48 hours through the cooling of the pressurizer that would occur during the course of a plant cooldown. This time (48 hours) exceeds the recommended RHR initiation time of 36 hours. In addition, the alternate means to rapidly reduce pressurizer pressure by use of the pressurizer power operated relief valves (PORV) is also dependent on the plant air systems. The valves at the Ginna plant are air-operated, so the nitrogen accumulators used for the LTOPS would have to be connected for the PORV's to be available to depressurize the RCS to RHR initiation pressure. The current shutdown and cooldown procedures for the Ginna facility do not include this method of depressurization.

The licensee has also provided an evaluation* to show that under the specific conditions of using Lake Ontario water as feedwater to maintain decay heat removal, operation for several days would not result in significant effects on steam generator integrity.

Based on this evaluation, the staff has concluded that the licensee should ensure that the following modifications are made to plant operating procedures:

Operating instructions for controlled operation of the PORVs with a loss of plant air should be provided.

The procedures for use of service water as steam generator feedwater should caution the operator as to the potential effects of long-term use of raw water in the steam generator.

*Pearl, W. L., et. al., "Use of Lake Ontario Water in Steam Generators During Hot Shutdown," NWT 167, transmitted by letter from J. E. Maier (RG&E) to D. M. Crutchfield (NRC), June 23, 1981.

TABLE I

Plant: GINNA Power (MW): 1520

Normal Operating Temp. (°F): 540

Safety valve lift (psig): 1140

Initial secondary inventory (lbm): 152,000 (in two steam generators)

Secondary makeup water temp. (°F): 80

S/RV flow area (ft^2): 0.040 (one atmospheric dump valve)

Emerg. Condenser total ht. xfer. coeff. (BTU/°F): NA

Stored sensible heat (BTU/°F): metal - 420,000 water - 300,000

core - 25,000

RHR Parameters: Design pressure - 600 psig.

Normal initiation - 410 psig, 350°F.

Design temperature - 400°F.

Pure water onsite (lbm):

125,100 - Condensate Storage Tank (technical specification minimum)

Cooldown assumptions:

1. At t=0 reactor trips.
2. Decay heat is in accordance with proposed ANS 5.1 (1973).
3. Plant remains at hot shutdown for four hrs. prior to cooldown.
4. The secondary (steam generator or emerg. condenser) is considered dry when 10% of the initial inventory remains.
5. Relief valve mass flow rate is in accordance with the Moody critical flow model.

TABLE 2

Plant: GINNA

Phase I (reactor trip to safety lift):

Time to safety valve lift (sec): greater than 600

Phase II (safety valve lift to cooldown start):

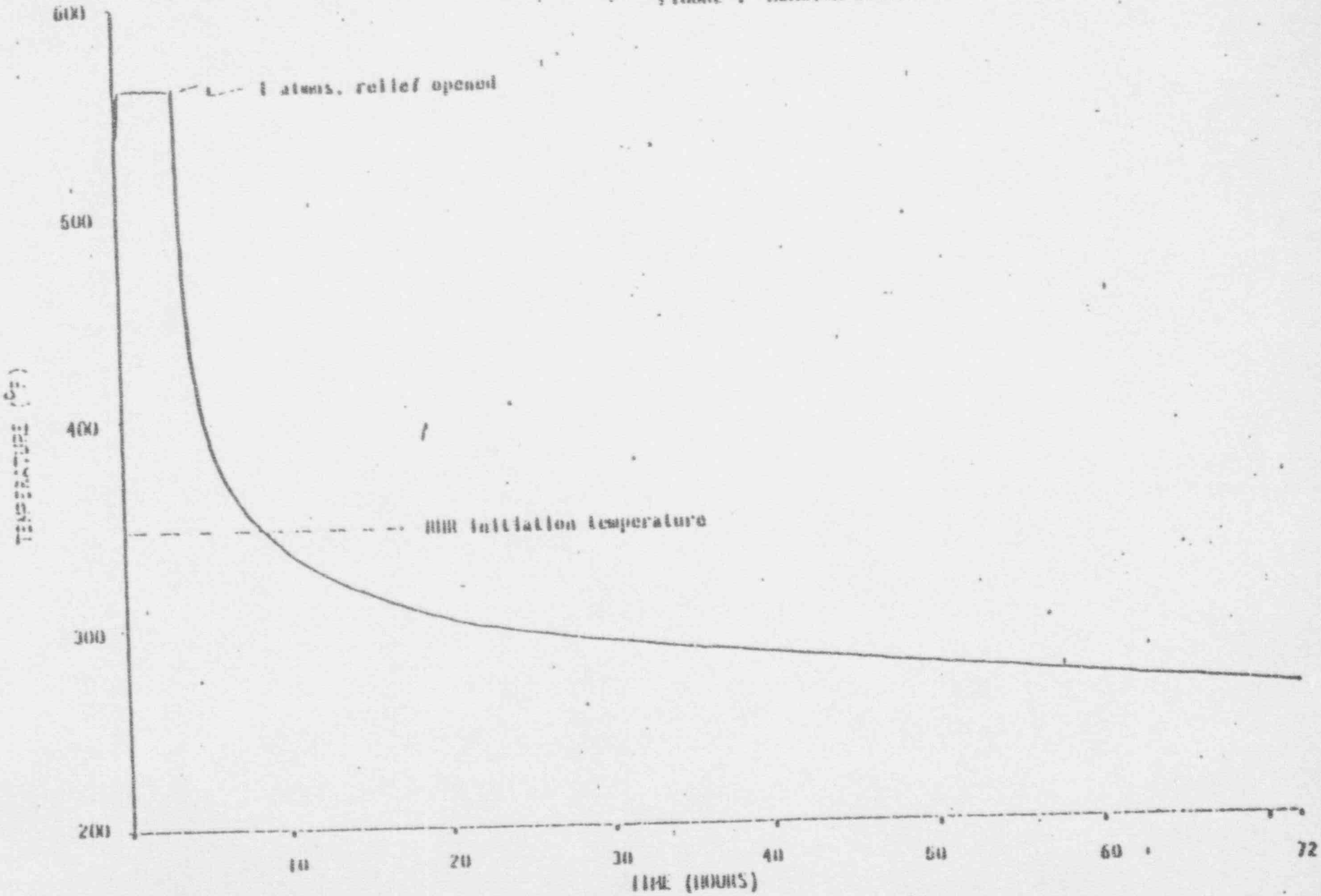
Time to boil secondary dry, assume no feedwater (min): 55
Decay heat generated prior to cooldown start (BTU): 255E6
Feedwater expended prior to cooldown start (lbm): 203,345

Phase III (cooldown): (1 atmospheric dump valve)

Time (hrs)	Temperature (°F)	Pressure (psia)	Decay heat generated (BTU)
4	562	*	255E6
5	418		300E6
6	381		341E6
12	329		553E6
36	298		1180E6
72	270		1950E6

*RCS pressure is controlled independently of RCS temperature. See EVALUATION section.

FIGURE 1 REACTOR SYSTEM TEMPERATURE VS TIME



Attachment 3

(Copies of NUREG-0916 should be available in your office files. If not, please contact SECY for a copy.)

NUREG-0916

Safety Evaluation Report
related to the restart of R. E. Ginna Nuclear Power Plant

Docket No. 50-244

Rochester Gas and Electric Corporation

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

May 1982

Attachment 4

SIERRA CLUB

530 Bush Street San Francisco, California 94108 (415) 981-8634

Reply to: 278 Washington Blvd.
Oswego, New York 13126

JUN 14 A10:35

June 10, 1982

Chairman Nunzio J. Palladino
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Chairman Palladino:

On March 11, 1982, the Sierra Club filed a show cause petition with the Office of Nuclear Reactor Regulation requesting that the Ginna operating license be suspended or, in the alternative, permission to restart the reactor be withheld, until critical safety issues were reviewed relating to the January 25th accident. On May 22, the Sierra Club was served with a response to its petition. The response made extensive reference to the "Safety Evaluation Report Related to the Restart of the R.E. Ginna Nuclear Power Plant", NUREG 0916, which was issued the same day and which constituted staff permission for the restart of the reactor.

Although the Sierra Club was not given an opportunity to review the NNR's response prior to restart, we have now completed a preliminary review of the staff response, including NUREG 0916. Our review leads us to conclude that several critical safety issues raised in our petition have not been adequately dealt with by staff and that permission for restart should not have been granted before proper resolution of these issues had occurred. We wish to bring these issues to your attention at this time and to encourage the Commission to exercise its authority under 10 CFR 2.206(c) to review these issues raised in the show cause petition.

A. Thermal shock. The Sierra Club finds staff's discussion of thermal shock consequences to the reactor (Club petition at #13) to be seriously deficient. The Safety Evaluation Report does not discuss reactor material properties and irradiation effects except in the most cursory manner and fails to provide adequate analysis of the B loop circulation during the course of the accident.

1. Properties of vessel, nozzle and welds. In the SER, staff fails to evaluate material supplied by licensee in its April 12th report, "Incident Evaluation, Ginna Steam Generator Tube Failure Incident," and in its April 26th supplement, "Affect of Thermal Transient on Reactor Coolant System." These reports discuss the material properties and irradiation effects of the beltline vessel weld, the reactor vessel nozzle and nozzle weld. We have reviewed these reports and wish to bring to the Commission's attention several deficiencies which we consider to be significant.

a. Inlet nozzle to vessel weld. Licensee analyzes the properties of the vessel nozzle, but fails to make any mention of the fact that "an indication in the inlet nozzle N2B to vessel weld that exceeded Code allowable limits was detected" during the in-service inspection performed February-March, 1979, and that the flaw was found to be 0.9 inches in length. (Source: NUREG 0569, "Evaluation of the Integrity of SEP Reactor Vessels," Appendix G, page 80, emphasis added.) At the same time, licensee takes pains to point out that past in-service inspection of the nozzle corners has shown them "to be free of unacceptable ultrasonic indications." (April 12th report at 6.4-3) Although the licensee discusses critical flaw depths for the nozzle, there is again no mention of the nozzle weld. Given that 0.75" is found to be sufficient for a flaw to initiate at the surface of the nozzle itself and to propagate in length and that a flaw deeper than 1.9" can propagate through the thickness of the nozzle, the Sierra Club finds it surprising that the 0.9" weld flaw is ignored.

b. Beltline weld analysis. NUREG 0569 has determined that the beltline weld is the limiting reactor vessel material(Ibid. at 78). Yet licensee's analysis of the potential impact of the Ginna accident on the beltline weld is not sufficiently conservative. The "no warm prestressing" assumption, used for the perfect mixing case, is dropped when the imperfect mixing case is considered. Licensee asserts that, having used the conservative mixing assumption, they should not also have to add the conservative assumption of "no warm prestressing." They conclude: "For the no mixing case, using the modified Reg. Guide 1.99 trend curve and the warm prestressing principle, no flaw was found to initiate." (April 26th report at 4.1) This leaves the reader wondering whether a flaw would be found to initiate when warm prestressing is not assumed. Staff should have required that this question be answered.

2. Staff analysis of B loop circulation. The thermal shock analysis provided by the Task Force in NUREG 0909 and reiterated with some elaboration in NUREG 0916 at 3.5.2, is not, in our opinion, adequate to support staff's contention that flow reversal in the B loop prevented cold water as measured by the temperature sensor from entering the reactor vessel.

Staff has apparently made no attempt to model the hydrodynamics of the primary loop flow during the period of temperature drop. Such a model must not only account for the mass balance, but also for all relevant dynamics such as buoyant and viscous forces and turbulent mixing. Lacking such a model which integrates the various forces, staff's attempts at explanation of the system dynamics remain unconvincing. For instance, staff suggests that the steam generator is a heat source which causes loss of natural circulation flow in the B-loop, without mentioning any other factors which would effect flow.

Other potentially important dynamics are ignored by staff. For instance, staff fails to discuss the flow consequences of the RCS pressure falling below the S/G B pressure, resulting in reverse flow through the tube rupture during the PORV openings. Nor does staff attempt to analyze the dynamics by which water lost from the B loop through the burst tube and PORV is replaced in the system. The question of stratified flow with some cold safety injection water being drawn into the reactor is certainly not answered by staff's vague reference to use of EPRI data. (NUREG 0916 at 3-15)

Staff asserts that even if cold water had entered the reactor, fracture mechanics analysis indicates that there would be no crack initiation. We are given almost no information about this analysis; however, we are told that the temperature used was that measured by the sensor in the cold leg of the B loop. (Ibid.at 3-15) This is portrayed as a worst case analysis, despite staff's recognition on the previous page that the temperature entering the reactor could be 10° less than the measured temperature.

c. Conclusion. In summary, the Sierra Club finds the presentation in Section 3.5 of NUREG 0916 to be incomplete and unconvincing. Substantial question remains regarding thermal shock to the reactor. The existence of the nozzle weld flaw is never mentioned by licensee or staff. Nor has the fracture mechanics analysis been truly conservative. Given the resulting uncertainty combined with the age of the Ginna reactor (8 EFPY), the prudent course would be to require ultrasonic testing of the reactor vessel and nozzle weld. Such testing should take advantage of newer techniques which use multi-angled probes and time of flight information as recommended by Cottrell (New Scientist 25 March 1982, page 775). Such testing should be required before the Commission allows continued operation of the reactor.

B. Safety valve. The Sierra Club considers staff response regarding the safety significance of the steam generator safety valve malfunction and the lack of any proposed corrective action to be an unacceptable response to the Club petition #11b. We wish to bring this concern to the Commission's attention.

The Task Force, appointed by the Commission, determined that the safety valve opened and closed five times. Staff in NUREG 0916 notes the Task Force findings regarding the malfunction of the valve in the following passage:

> "NUREG 0909 also notes that the valve opened and closed at generally decreasing pressures and discussed a possible reason for the decreasing closing pressures; the possibility of some steam leakage after closing the first time, and water leakage estimated at 100 gpm after the last closing. The NUREG attributed the water leakage to the likelihood of failure to fully reseat after the last closing until 50 minues later when the valve apparently stopped leaking."
> (NUREG 0916 at 6-11)

Despite this release of approximately 5000 gallons of cooling water contaminated via the tube rupture and released directly to the environment, the staff concludes "that the valve behavior was entirely within its design basis," (Ibid at 6-12) and that "The performance of the steam generator safety valve that opened was satisfactory."

(Ibid. at 6-14). The Sierra Club is shocked by staff's conclusions. When the safety valve leaks or sticks open, there is no way operators can close the valve manually. Nor can a block valve be closed. During a SGTR accident, the safety valve is a direct path for loss of radioactive steam or water to the environment. The potential for exceeding Part 100 release limits during a design basis SGTR accident is discussed in the next section. Given this scenario, staff's conclusion that the safety valve is acceptable does not serve to increase citizen confidence in the nuclear industry's ability to protect public health and safety. We are not reassured by staff's decision to give the licensee 6 months in which to review its procedures for a tube rupture with failed SG safety or relief valve. (Ibid. at 4.1.12)

If the safety valve malfunctioned while still meeting the design basis specifications, then the specifications are clearly inadequate. The Ginna reactor should not be allowed to operate without an improved safety valve.

C. Iodine release. Staff recognizes, as a result of the Ginna accident, that "the potential exists for doses [of iodine to be released] exceeding Part 100 Guidelines for a design-basis SGTR accident." (Ibid. at 8-1) As recently as June 25, 1981, staff's analysis of such an accident contained in "Systematic Evaluate Program Evaluation of a Steam Generator Tube Rupture Accident at Ginna" had not considered the possibility of substantial amounts of water and steam being released through the safety valve. The inability of staff to model possible accident parameters accurately in advance of an accident lays open to question the basis on which regulations are promulgated.

While we commend staff's caution in reducing the spiking and equilibrium concentration limits for iodine in the primary coolant, we note that staff is willing to remove these stricter standards if licensee can demonstrate that steam generator flooding will not occur. (Ibid. at 8.1) Yet the steam generator did flood with water when it was not expected to do so. At the very least there should be a "lesson learned" from the Ginna accident that such flooding should be part of a design basis SGTR accident.

We note that staff again avoids dealing with the fact that the safety valve is not designed to handle water, or to be cycled open and closed. Staff suggests that the steam generator PORV is better suited for cycling and so "may be better to use." (Ibid. at 8-3) However, staff concedes earlier in its discussion that the relief valve is also subject to malfunction. They state:

> "Two-phase flow through the relief or safety valves may contribute to valve degradation and possible failures to reseat. This can contribute to the radiological consequences by providing a rpolonged pathway to the environment." (Ibid. at 8.1, emphasis added.)

Thus, simply changing the emergency operator guidelines to ensure that the block valve is not closed incorrectly will not remedy the problem. Staff has approved other changes which relate to termination of the safety injection. We are concerned that these changes may have ramifications for core cooling. We are particularly concerned about the following note to be added after STEP 3.15.3:

> "Termination of SI with suspected voids in the upper RV head is allowed when natural circulation is verified." (Ibid. at 8.1)

The Ginna accident has demonstrated how difficult it can be to verify natural circulation. We find no analysis of the consequences of terminating SI with a vessel void, if operators make an error in verifying natural circulation. Nor do we find any analysis of possible adverse consequences of adding STEP 3.20.3 which requires that operators "Block SI before the faulted S/G drops below 550 psig."

Staff admits that there has been "incomplete evaluation of the effects of changes to operator guidelines," (Ibid.) which is one reason the iodine limits are being lowered. The Sierra Club urges the Commission to reconsider the wisdom of allowing Ginna to restart when operating guidelines have been changed without complete evaluation of the safety repurcussions of these changes.

D. Steam Generator Tubes. In response to concerns raised in Sierra Club's petition at #2 a, b, c and #3 regarding in-service inspection standards and specifications for tube rejection, staff simply renumerates the current standards and RG&E procedures. There is no recognition by staff that the inability to anticipate the January 25th tube burst, despite recurrent problems in wedge area #4 and eddy current indication in April, 1981, for the tube that later burst, should be a warning that the standards are not adequate. The Sierra Club is concerned that staff has avoided dealing with the implications of the tube burst and urges the Commission to review the adequacy of these standards.

E. PORV. The Sierra Club raised the concern that the PORV is not required to be safety grade in its petition at #7 and asked for staff review in light of the Ginna accident and the failure of the PORV. Staff has responded that a generic study is underway. (Denton response of May 22, page 5) The fact that a specific cause has been determined for the Ginna PORV failure in no way obviates the importance of making the PORV safety grade. How many accidents involving a malfunction of the PORV need to take place before the staff determines that these valves need to be upgraded? This question is ripe for Commission consideration.

The points raised in this letter are intended only to highlight our concerns regarding staff's response to our petition and are not an exhaustive discussion of every concern. The Sierra Club is hopeful that the Commission, sharing the safety concerns which we have raised herein, will review our petition on its own motion and will reverse staff's decision to allow restart of the Ginna reactor before critical safety issues have been adequately resolved.

While in this letter we have focused specifically on the implications of the accident for the safe operation of the Ginna reactor, we do wish to note that a number of the issues raised have potentially generic significance. Where generic investigations are not already underway, we hope that the Commission will institute such proceedings so that the "lessons learned" from the Ginna accident will not be lost.

Very truly yours,

Ruth N. Caplan, Chair
National Energy Committee
Sierra Club

cc. Samuel J. Chilk, Secretary to the Commission

Attachment 5

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

OFFICE OF THE SECRETARY

MEMORANDUM FOR: William J. Dircks
Executive Director for Operations

FROM: Samuel J. Chilk
Secretary

SUBJECT: SIERRA CLUB LETTER REGARDING GINNA 2.206 PETITION

Attached please find a letter dated June 10 from the Sierra Club to Chairman Palladino regarding your decision on the Sierra Club's March 11, 1982 2.206 petition. The Commission has directed that this letter be referred to you for appropriate consideration under 10 CFR 2.206.

Attachment: Sierra Club letter 6/10