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

DOCKET

May 11, 1981

Docket No. 50-244
LS05-81-05-016

RECEIVED
MAY 27 1981
U.S. NUCLEAR REGULATORY COMMISSION

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

Dear Mr. Maier:

SUBJECT: TMI-2 Category "A" Items

The Commission has issued the enclosed Amendment No. 42 to Provisional Operating License No. DPR-18 for the R. E. Ginna Nuclear Power Plant. This amendment consists of changes to the Technical Specifications in response to your application dated November 13, 1980.

Your application was submitted pursuant to our letter of July 2, 1980 (to all pressurized water reactor licensees) that requested specifications to assure operation of Ginna within the limits determined acceptable following the implementation of the Three Mile Island Unit 2 Lessons Learned Category "A" items. We have reviewed your proposed technical specifications against our model specifications issued by our July 2, 1980 letter and have considered plant-specific differences and differences that are the result of your not having adopted Standard Technical Specifications for the Ginna plant. We have also modified several of the specifications as mutually agreed upon during telephone conversations with members of your staff. After such modification, we have concluded that the specifications are satisfactory.

We have also included in this amendment changes to Technical Specification figures 6.2-1 and 6.2-2 regarding the Shift Technical Advisor and Technical Assistant for Operational Assessment in the Ginna organization. The change to Figure 6.2-1 was originally submitted by your application notarized

8105290477

P

April 9, 1980 (transmitted by letter dated April 11, 1980) but superseded by your application notarized October 30, 1980 (transmitted by letter dated November 4, 1980) and by the application resulting in this present action. See Amendment No. 35 to License DPR-18 dated February 10, 1981 for additional information on this subject.

Copies of the related Safety Evaluation and the Notice of Issuance are also enclosed.

Sincerely,

Original signed by

Dennis M. Crutchfield, Chief
Operating Reactors Branch #5
Division of Licensing

Enclosures:
1. Amendment No. 42 to License No. DPR-18
2. Safety Evaluation
3. Notice of Issuance

cc w/enclosures:
See next page

DISTRIBUTION
Docket
NRC PDR
Local PDR
ORB Reading
ACRS (10)
TBarnhart (4)
BScharf (10)
OI&E (3)
OELD
NSIC
TERA
DRuctchfield
HSmith
DSnaider
JOlshinski
DVassallo

TAC 43283

an additional change added per call from licensee. HS 5/11/81 5/11/81

Held up for 5/6/81 Correction letter re: Amend #38 HS 5/7/81

see comment on Amendment #

OFFICE	DL: ORB #5	DL: ORB #5	OELD	DL: ~~ORAB~~	DHFS: LQB	DL: ORB #5	DL: AD/SA
SURNAME	DSnaider:cc	HSmith	KETCHEN	~~JOlshinski~~	DVassallo	DCRutchfield	GLainas
DATE	3/23/81	3/17/81	4/16/81	~~4/16/81~~	4-16-81	4/20/81	4/21/81

April 9, 1980 (transmitted by letter dated April 11, 1980) but was superseded by your application notarized October 30, 1980 (transmitted by letter dated November 4, 1980) and by the application resulting in this present action. See Amendment No. 35 to License DPR-18 dated February 10, 1981 for additional information on this subject.

Copies of the related Safety Evaluation and the Notice of Issuance are also enclosed.

Sincerely,

Dennis M. Crutchfield

Dennis M. Crutchfield, Chief
Operating Reactors Branch #5
Division of Licensing

Enclosures:
1. Amendment No. 42 to
   License No. DPR-18
2. Safety Evaluation
3. Notice of Issuance

cc w/enclosures:
See next page

cc
Harry H. Voigt, Esquire
LeBoeuf, Lamb, Leiby and MacRae
1333 New Hampshire Avenue, N. W.
Suite 1100
Washington, D. C. 20036

Mr. Michael Slade
12 Trailwood Circle
Rochester, New York 14618

Rochester Committee for
Scientific Information
Robert E. Lee, Ph.D.
P. O. Box 5236 River Campus
Station
Rochester, New York 14627

Jeffrey Cohen
New York State Energy Office
Swan Street Building
Core 1, Second Floor
Empire State Plaza
Albany, New York 12223

Director, Technical Development
Programs
State of New York Energy Office
Agency Building 2
Empire State Plaza
Albany, New York 12223

Rochester Public Library
115 South Avenue
Rochester, New York 14604

Supervisor of the Town
of Ontario
107 Ridge Road West
Ontario, New York 14519

Resident Inspector
R. E. Ginna Plant
c/o U. S. NRC
1503 Lake Road
Ontario, New York 14519

Ezra I. Bialik
Assistant Attorney General
Environmental Protection Bureau
New York State Department of Law
2 World Trade Center
New York, New York 10047

Director, Criteria and Standards
Division
Office of Radiation Programs
(ANR-460)
U. S. Environmental Protection
Agency
Washington, D. C. 20460

U. S. Environmental Protection
Agency
Region II Office
ATTN: EIS COORDINATOR
26 Federal Plaza
New York, New York 10007

Herbert Grossman, Esq., Chairman
Atomic Safety and Licensing Board
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Dr. Richard F. Cole
Atomic Safety and Licensing Board
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Dr. Emmeth A. Luebke
Atomic Safety and Licensing Board
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Mr. Thomas B. Cochran
Natural Resources Defense Council, Inc.
1725 I Street, N. W.
Suite 600
Washington, D. C. 20006

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

ROCHESTER GAS AND ELECTRIC CORPORATION

DOCKET NO. 50-244

R. E. GINNA NUCLEAR POWER PLANT

AMENDMENT TO PROVISIONAL OPERATING LICENSE

Amendment No. 42
License No. DPR-18

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Rochester Gas and Electric Company (the licensee) dated November 13, 1980, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment and by adding two new paragraphs 2.C(7) and 2.C(8) and changing Paragraph 2.C(2) of Provisional Operating License No. DPR-18 to read as follows:

2.C(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 42 , are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

2.C(7) Systems Integrity

The licensee shall implement a program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as low as reasonably achievable levels. This program shall include the following:

1. Provisions establishing preventive maintenance and periodic visual inspection requirements, and

2. Leak test requirements for each system at a frequency not to exceed refueling cycle intervals.

2.C(8) Iodine Monitoring

The licensee shall implement a program which will ensure the capability to accurately determine the airborne iodine concentration in vital areas under accident conditions. This program shall include the following:

1. Training of personnel,

2. Procedures for monitoring, and

3. Provisions for maintenance of sampling and analysis equipment.

3. This license amendment is effective as of the date of its issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Dennis M. Crutchfield

Dennis M. Crutchfield, Chief
Operating Reactors Branch #5
Division of Licensing

Attachment:
Changes to the Technical
Specifications

Date of Issuance: May 11, 1981

ATTACHMENT TO LICENSE AMENDMENT NO. 42

PROVISIONAL OPERATING LICENSE NO. DPR-18

DOCKET NO. 50-244

Revise Appendix A Technical Specifications by removing the pages identified below and inserting the enclosed pages. The revised pages contain the captioned amendment number and a vertical line which indicated the area of change. Some page changes have been included only because of the reformatting necessitated by the numerous additions to the specifications.

REMOVE	INSERT
ii	ii
1-5	1-5
2.3-4	2.3-4
2.3-7	2.3-7
2.3-9	2.3-9
3.1-2	3.1-2
3.1-3	3.1-3
3.1-4	3.1-4
--	3.1-4a
3.4-1	3.4-1
3.4-2	3.4-2
3.4-3	3.4-3
3.4-4	--
3.5-1	3.5-1
3.5-2	3.5-2
3.5-6	3.5-6
--	3.5-7
--	3.5-8
--	3.5-9
--	3.5-10
--	3.5-11
--	3.5-12
--	3.5-13
--	3.5-14
3.6-1	3.6-1
3.6-2	3.6-2
--	3.6.3

REMOVE	INSERT
--	3.6-4
--	3.6-5
--	3.6-6
--	3.6-7
--	3.6-8
--	3.6-9
--	3.6-10
4.1-1	4.1-1
4.1-7	4.1-7
--	4.1-11
4.3-1	4.3-1
4.3-2	4.3-2
--	4.3-3
4.4-5a	4.4-5a
4.4-5b	4.4-5b
4.4-5c	4.4-5c
4.4-8	4.4-8
4.4-14	4.4-14
4.8-2	4.8-2
4.8-3	4.8-3
6.2-2	6.2-2
6.2-3	6.2-3
6.3-1	6.3-1

TABLE OF CONTENTS (cont.)

Amendment No. ~~15~~, ~~26~~, ~~36~~, 42

1.12 Frequency Notation

The frequency notation specified for the performance of surveillance requirements shall correspond to the intervals defined below.

Notation	Frequency
S, Each Shift	At least once per 12 hours
D, Daily	At least once per 24 hours
Twice per week	At least once per 4 days and at least twice per 7 days
W, Weekly	At least once per 7 days
B/W, Biweekly	At least once per 14 days
M, Monthly	At least once per 31 days
B/M, Bimonthly	At least once per 62 days
Q, Quarterly	At least once per 92 days
SA, Semiannually	At least once per 6 months
A, Annually	At least once per 12 months
R, Refueling	At least once per 18 months
S/U	Prior to each startup
NA	Not Applicable
P	Prior to each startup if not done previous week

f. Low reactor coolant flow - $\geq$ 90% of normal indicated flow.

g. Low reactor coolant pump frequency - $\geq$ 57.5 Hz.

2.3.1.3 Other reactor trips

a. High pressurizer water level - $\leq$ 88 % of span

b. Low-low steam generator water level - $\geq$16 % of narrow range instrument span

2.3.2 Protective instrumentation settings for reactor trip interlocks shall be as follows:

2.3.2.1 Remove bypass of "at power" reactor trips at high power (low pressurizer pressure and low reactor coolant flow) for both loops:

Power range nuclear flux - $\leq$ 8.5% of rated power

(1) (Note: During cold rod drop tests, the pressurizer high level trip may be bypassed.)

2.3.2.2 Remove bypass of single loss of flow trip at high power:

Power range nuclear flux - $\leq$ 50% rated power

2.3.3* Relay operating will be tested to insure that they perform according to their design characteristics which must fall in within the ranges defined below:

2.3.3.1* Loss of voltage relay operating time $\leq$ 8.5 seconds for 480 volt safeguards bus voltages $\leq$ 368 volts. Measured values shall fall at least 5% below the theoretical limit. This 5% margin is shown as the 5% tolerance curve in Figure 2.3-1.

*Effective 30 days after completion of necessary modifications and no later than completion of the Spring 1982 refueling outage.

Amendment No. ~~38~~, 42
(Correction - May 6 1981)

In the power range of operation, the overpower nuclear flux reactor trip protects the reactor core against reactivity excursions which are too rapid to be protected by temperature and pressure protective circuitry. The overpower limit criteria is that core power be prevented from reaching a value at which fuel pellet centerline melting would occur. The reactor is prevented from reaching the overpower limit condition by action of the nuclear overpower and overpower ΔT trips.

The high and low pressure reactor trips limit the pressure range in which reactor operation is permitted. The high pressurizer pressure reactor trip is also a backup to the pressurizer code safety valves for overpressure protection, and is therefore set lower than the set pressure for these valves (2485 psig). The low pressurizer pressure reactor trip also trips the reactor in the unlikely event of a loss of coolant accident.(3)

The overtemperature ΔT reactor trip provides core protection against DNB for all combinations of pressure, power, coolant temperature, and axial power distribution, provided only that: (1) the in the accident analysis.[7] The underfrequency reactor trip protects against a decrease in flow caused by low electrical frequency. The specified set point assures a reactor trip signal before the low flow trip point is reached.

The high pressurizer water level reactor trip protects the pressurizer safety valves against water relief. Approximately 700 ft.^{3} of water corresponds to 92% of span. A trip at this set point contains margin for both normal instrument error and transient overshoot of level beyond this trip setting. An additional 4% instrument error has been assumed to account for the effects of elevated temperatures on level measurement in accordance with IE Bulletin 79-21. (12) Therefore a trip setpoint of 88% prevents the water level from reaching the safety valves.(2)

The low-low steam generator water level reactor trip protects against loss of feedwater flow accidents. A set point of 5% is equivalent to at least 40,000 lbs. of water and assures that there will be sufficient water inventory in the steam generators at the time of trip to allow for starting delays for the auxiliary feedwater system.[8] An additional 11% has been added to the set point to account for error which may be introduced into the steam generator level system at a containment temperature of 286°F as determined by an evaluation performed for temperature effects on level measurements required by IE Bulletin 79-12.

The specified reactor trips are blocked at low power where they are not required for protection and would otherwise interfere with normal plant operations. The prescribed set point above which these trips are unblocked assures their availability in the power range where needed.

Operation with one pump will not be permitted above 130 MWT (8.5%). An orderly power reduction to less than 130 MWT (8.5%) will be accomplished if a pump is lost while operating between 130 MWT (8.5%) and 50%. Automatic protection is provided so that a power-to-flow ratio is maintained equal to or less than one, which insures that the minimum DNB ratio increases at lower flow

References:

(1) FSAR 14.1.1

(2) FSAR, Page 14-3

(3) FSAR 14.3.1

(4) FSAR 14.1.2

(5) FSAR 7.2, 7.3

(6) FSAR 3.2.1

(7) FSAR 14.1.6

(8) FSAR 14.1.9

(9) Letter from L. D. White, Jr. to A. Schwencer, NRC, dated September 30, 1977

(10) Letter from L. D. White, Jr. to A. Schwencer, NRC, dated September 30, 1977

(11) Letter from L. D. White, Jr. to D. Ziemann NRC, dated July 24, 1978

(12) Letter from L. D. White, Jr. to B. Grier, USNRC dated September 14, 1979.

3.1.1.1 d. At least one reactor coolant pump shall be in operation for a planned transition from one Reactor Operating Mode to another involving an increase in the boron concentration of the reactor coolant, except for emergency boration.

e. A reactor coolant pump shall not be started with one or more of the RCS cold leg temperatures $\leq$ 330°F unless 1) the pressurizer water volume is less than 324 cubic feet (38% level) or 2) the secondary water temperature of each steam generator is less than 50°F above each of the RCS cold leg temperatures.

3.1.1.2 Steam Generator

a. One steam generator shall be capable of performing its heat transfer function whenever the average coolant temperature is above 350°F.

b. The temperature difference across the tube sheet shall not exceed 100°F.

3.1.1.3 Safety Valves

a. During cold shutdown or refueling when the reactor head is bolted on the vessel, at least one pressurizer code safety valve shall be operable with a lift setting of 2485 psig ± 1%.

b. If the conditions of 3.1.1.3.a are not met, immediately suspend all operations involving positive reactivity changes and place an operable RHR loop into operation in the shutdown cooling mode.

c. Whenever the reactor is at hot shutdown or critical, both pressurizer code safety valves shall be operable with a lift setting of 2485 psig ± 1%.

d. If one pressurizer code safety valve is not operable while the reactor is at hot shutdown or critical, then either restore the inoperable valve to operable status within 15 minutes or be in at least hot shutdown within 6 hours and below a Tavg of 350°F within an additional 6 hours.

3.1.1.4 Relief Valves

a. Both pressurizer power operated relief valves (PORVs) and their associated block valves shall be operable whenever the reactor is at hot shutdown or critical.

Change No. ~~12~~
Amendment No. ~~23~~, ~~26~~, 42

b. With one or more PORV(s) inoperable, within 1 hour either restore the PORV(s) to operable status or close the associated block valve(s); otherwise, be in at least hot shutdown within the next 6 hours and in cold shutdown within the following 30 hours.

c. With one or more block valve(s) inoperable, within 1 hour either restore the block valve(s) to operable status or close the block valve(s) and remove power from the block valve(s); otherwise, be in at least hot shutdown within the next 6 hours and in cold shutdown within the following 30 hours.

3.1.1.5 Pressurizer

Whenever the reactor is at hot shutdown or critical the pressurizer shall have at least 100 kw of heaters operable and a water level maintained between 12% and 87% of level span. If the pressurizer is inoperable due to heaters or water level, restore the pressurizer to operable status within 6 hrs. or have the RHR system in operation within an additional 6 hrs.

Bases:

When the boron concentration of the reactor coolant system is to be reduced the process must be uniform to prevent sudden reactivity changes in the reactor. Mixing of the reactor coolant will be sufficient to prevent a sudden increase in reactivity if at least one reactor coolant pump or one residual heat removal pump is running while the change is taking place. The residual heat removal pump will circulate the primary system volume in approximately one half hour. The pressurizer is of no concern because of the low pressurizer volume and because the pressurizer boron concentration will be higher than that of the rest of the reactor coolant. When the boron concentration of the reactor coolant system is to be increased, the process must be uniform to prevent sudden reactivity increases in the reactor during subsequent startup of the reactor coolant pumps. Mixing of the reactor coolant will be sufficient to maintain a uniform boron concentration if at least one reactor coolant pump is running while the change is taking place. Emergency boration without a reactor coolant pump in operation is not prohibited by this specification.

Change No. ~~12~~
Amendment No. ~~23~~, 42

The specification requires that a sufficient number of reactor coolant pumps be operating to provide core cooling. The flow provided in each case will keep DNBRwell above 1.30 as discussed in FSAR Section 14.1.6. Therefore, cladding damage and release of fission products to the reactor coolant will not occur. Heat transfer analyses[1] show that reactor heat equivalent to 130 MWT (8.5%) can be removed with natural circulation only; hence, the specified upper limit of 1% rated power without operating pumps provides a substantial safety factor.

Each of the pressurizer code safety valves is designed to relieve 288,000 lbs. per hr. of saturated steam at the valve set point. Below 350°F and 350 psig in the reactor coolant system, the residual heat removal system can remove decay heat and thereby control system temperature and pressure. If no residual heat were removed by any of the means available the amount of steam which could be generated at safety valve relief pressure would be less than half the valves' capacity. One valve therefore provides adequate defense against overpressurization.

Prohibiting reactor coolant pump starts without a large void in the pressurizer or without a limited RCS temperature differential will prevent RCS overpressurization due to expansion of cooler RCS water as it enters a warmer steam generator. A 38% level in the pressurizer will accommodate the swell resulting from a reactor coolant pump start with a RCS temperature of 140°F and steam generator secondary side temperature of 340°F, or the maximum temperature which usually exists prior to cooling the reactor with the RHR system.

The specification permits an orderly reduction in power if a reactor coolant pump is lost during operation between 130 MWT and 50% of rated power.[2] Above 50% power, an automatic reactor trip will occur if either pump is lost. The power-to-flow ratio will be maintained equal to or less than one which ensures that the minimum DNB ratio increases at lower flow since the maximum enthalpy rise does not increase.

Temperature requirements for the steam generator correspond with measured NDT for the shell and allowable thermal stresses in the tube sheet.

The power operated relief valves (PORVs) operate to relieve RCS pressure below the setting of the pressurizer code safety valves. These relief valves have remotely operated block valves to provide a positive shutoff capability should a relief valve become inoperable. The electrical power for both the relief valves and the block valves is capable of being supplied from an emergency power source to ensure the ability to seal this possible RCS leakage path.

The requirement that 100 kw of pressurizer heaters and their associated controls be capable of being supplied electrical power from an emergency bus provides assurance that these heaters can be energized during a loss of offsite power condition to maintain natural circulation at hot shutdown and during cooldown.[3]

References

(1) FSAR Section 14.1.6

(2) FSAR Section 7.2.3

(3) Letter from L. D. White, Jr. to D. L. Ziemann, USNRC, dated October 17, 1979

3.4 Turbine Cycle

Applicability

Applies to the operating status of turbine cycle.

Objective

To define conditions of the turbine cycle steam-relieving capacity. Auxiliary Feedwater System and Service Water System operation is necessary to ensure the capability to remove decay heat from the core. The Standby Auxiliary Feedwater System provides additional assurance of capability to remove decay heat from the core should the Auxiliary Feedwater System be unavailable.

Specification

3.4.1 When the reactor coolant temperature is above 350°F, the following conditions shall be met:

a. A minimum turbine cycle code approved steam-relieving capability of eight (8) main steam valves available (except for testing of the main steam safety valves).

b. Three auxiliary feedwater pumps and their associated flow paths (including backup supply from the Service Water System) must be operable.

c. A minimum of 22,500 gallons of water shall be available in the condensate storage tanks for the Auxiliary Feedwater System.

d. Two Standby Auxiliary Feedwater pumps and associated flow path (including flow path from the Service Water System) must be operable.

3.4.2 Actions To Be Taken If Conditions of 3.4.1 Are Not Met

a. With one or more main steam code safety valves inoperable, restore the inoperable valve(s) to operable status within 4 hours or be in at least hot shutdown within the next 6 hours and in cold shutdown within the following 30 hours.

b. With one auxiliary feedwater pump inoperable, restore the pump to operable status within 7 days. If the pump is not restored to operable status within 7 days submit a Thirty Day Written Report in accordance with Specification 6.9.2 outlining the cause of the inoperability and plans for restoring the pump to operable status.

Amendment No. ~~25~~, 42

c. With two auxiliary feedwater pumps inoperable, restore two pumps to operable status within 72 hours or be in hot shutdown within the next 12 hours (and in cold shutdown within the following 24 hours).

d. With one standby auxiliary feed pump inoperable, restore two pumps to operable status within 7 days or be in hot shutdown within the next 12 hours and cold shutdown within the following 24 hours.

e. With the required 22,500 gallons of water unavailable in the condensate storage tanks, within 4 hours, either:

   1. Restore the required amount of water or be in hot shutdown within 12 hours, or

   2. Demonstrate the operability of the Service Water System as a backup supply to the auxiliary feed system and restore the required amount of water in the condensate storage tanks within 7 days or be in hot shutdown within the following 12 hours.

Basis:

A reactor shutdown from power requires removal of core decay heat. Immediate decay heat removal requirements are normally satisfied by the steam bypass to the condenser. Therefore, core decay heat can be continuously dissipated via the steam bypass to the condenser as feedwater in the steam generator is converted to steam by heat absorption. Normally, the capability to return feedwater flow to the steam generators is provided by operation of the turbine cycle feedwater system.

The eight main steam safety valves have a total combined rated capability of 6,580,000 lbs/hr. This capability exceeds the total full power steam flow of 6,577,279 lbs/hr. In the event of complete loss of off-site electrical power to the station, decay heat removal is assured by either the steam-driven auxiliary feedwater pump or one of the two motor-driven auxiliary feedwater pumps, and steam discharge to the atmosphere via the main steam safety valves or atmospheric relief valves.(1)(2) The turbine driven pump can supply 200% of the required feedwater and one motor-driven auxiliary feedwater pump can supply 100% of the required feedwater for removal of decay heat from the plant, so any combination of two pumps can remove decay heat with a postulated single failure of one pump. The minimum amount of water in the condensate storage tanks is the amount needed to remove decay heat for 2 hours after reactor scram from full power.(4) An unlimited supply is available from the lake via either leg of the plant service water system for an indefinite time period.

Amendment No. ~~29~~, 42

The Standby Auxiliary Feedwater System is provided to give additional assurance of the capability to remove decay heat from the reactor. The system would be used only if none of the auxiliary feedwater pumps were available to perform their intended function. Since operability requirements are established for the auxiliary feedwater system, the Standby System would be required only if some unlikely event should disable all auxiliary feedwater pumps. The specified time to restore the Standby System to full capability is longer than for other components since the probability of being required to use the Standby System is extremely low.[3]

<u>References</u>:

(1) FSAR Section 10.4

(2) FSAR Section 14.1.9

(3) "Effects of High Energy Pipe Breaks Outside the Containment Building" submitted by letter dated November 1, 1973 from K. W. Amish, Rochester Gas and Electric Corporation to A. Giambusso, Deputy Director for Reactor Projects. U.S. Atomic Energy Commission

(4) L. D. White, Jr. letter to Mr. D. L. Ziemann, USNRC dated March 28, 1980

Amendment No. ~~29~~, 42

3.5 Instrumentation Systems

Applicability:

Applies to plant instrumentation systems.

Objective:

To delineate the conditions of the plant instrumentation and safety circuits.

Specification:

3.5.1 Operational Safety Instrumentation

3.5.1.1 The number of Minimum Operable Channels for instrumentation shown on Tables 3.5-1 through 3.5-3 shall be OPERABLE for plant operation at rated power.

3.5.1.2 In the event the number of channels of a particular sub-system in service falls below the limit given in the columns entitled Minimum Operable Channels, operation shall be limited according to the requirement shown in the last column of Tables 3.5-1 through 3.5-3.

3.5.2 Accident Monitoring Instrumentation

3.5.2.1 The accident monitoring instrumentation channels shown in Table 3.5-4 shall be operable whenever the reactor is at hot shutdown or is critical.

3.5.2.2 While critical, with the number of operable accident monitoring instrumentation channels less than the Total Number of Channels shown in Table 3.5-4, either restore the inoperable channel(s) to operable status within 7 days, or be in at least hot shutdown within the next 12 hours.

3.5.2.3 While critical, with the number of operable accident monitoring instrumentation channels less than the MINIMUM CHANNELS OPERABLE requirements of Table 3.5-4, either restore the inoperable channel(s) to operable status within 48 hours or be in at least hot shutdown within the next 12 hours.

3.5.3 Engineered Safety Feature Actuation Instrumentation

3.5.3.1 The Engineered Safety Feature Actuation System (ESFAS) instrumentation channels shown in Tables 3.5-2 and 3.5-3 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.5-5.

Amendment No. 42

3.5.3.2 With an instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.5-5, declare the channel inoperable and apply the applicable ACTION requirement of Tables 3.5-2 and 3.5-3 until the channel is restored to OPERABLE status with the trip setpoint adjusted consistent with the Trip Setpoint Value.

3.5.3.3 With an instrumentation channel inoperable, take the action shown in Tables 3.5-2 and 3.5-3.

Basis:

During plant operations, the complete instrumentation systems will normally be in service. Reactor safety is provided by the Reactor Protection System, which automatically initiates appropriate action to prevent exceeding established limits. Safety is not compromised, however, by continuing operation with certain instrumentation channels out of service since provisions were made for this in the plant design. This specification outlines limiting conditions for operation necessary to preserve the effectiveness of the reactor control and protection system when any one or more of the channels is out of service.

Almost all reactor protection channels are supplied with sufficient redundancy to provide the capability for channel calibration and test at power. Exceptions are backup channels such as reactor coolant pump breakers. The removal of one trip channel is accomplished by placing that channel bistable in a tripped mode; e.g., a two-out-of-three circuit becomes a one-out-of-two circuit. Testing does not trip the system unless a trip condition exists in a concurrent channel.

The operability of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess these variables during and following an accident. This capability is consistent with the recommendations of NUREG-0578, "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendation".

Reference:

FSAR - Section 7.2.1.

TABLE 3.5-2 (Continued)
EMERGENCY COOLING

FUNCTIONAL UNIT	1 NO. OF CHANNELS	2 NO. OF CHANNELS TO TRIP****	3 MIN. OPERABLE CHANNELS	4 MIN. DEGREE OF REDUNDANCY	5 PERMISSIBLE BYPASS CONDITIONS	6 OPERATOR ACTION IF CONDITIONS OF COLUMN 3 CANNOT BE MET
3. Auxiliary Feedwater						
Motor and Turbine Driven						
a. Manual	1/pump	1/pump	1/pump			1
b. Stm. Gen. Water Level-low-low						
i. Start Motor Driven Pumps	3/stm. gen.	2/stm. gen. either gen.	2/stm. gen.	1		2
ii. Start Turbine Driven Pump	3/stm. gen.	2/stm. gen. both gen.	2/stm. gen.	1		2
c. Loss of 4 KV Voltage Start Turbine Driven Pump	2/bus	1/bus both buses	1/bus			2
d. Safety Injection Start Motor Driven Pumps		(see Item 1)				
e. Trip of both Feed-water Pumps starts Motor Driven Pumps *****	2/pump	1/pump both pumps	1/pump	-		2
Standby Motor Driven						
a. Manual	1/pump	1/pump	1/pump	-		1

TABLE 3.5-2 (Continued)

TABLE NOTATION

ACTION STATEMENTS

****	If a functional unit is operating with the minimum operable channels the number of channels to trip the reactor will be column 3 less column 4.
*****	This start signal is required only during power operation above 5%.
ACTION 1	With the number of operable Channels one less than the Total Number of Channels, restore the inoperable channel to operable status within 48 hours or be in at least hot shutdown within the next 6 hours and in cold shutdown within the following 30 hours.
ACTION 2	With the number of operable channels one less than the Total Number of Channels, operation may proceed until performance of the next required CHANNEL FUNCTIONAL TEST provided the inoperable channel is placed in the tripped condition within 1 hour.

TABLE 3.5-3
INSTRUMENT OPERATING CONDITIONS FOR ISOLATION FUNCTIONS

FUNCTIONAL UNIT	1 TOTAL NO. OF CHANNELS	2 NO. OF CHANNELS TO TRIP*	3 MIN. OPERABLE CHANNELS	4 MIN. DEGREE OF REDUNDANCY	5 OPERATOR ACTION IF CONDITIONS OF COLUMN 3 CANNOT BE MET
1. CONTAINMENT ISOLATION					
1.1 Containment Isolation					
a. Manual	2	1	1		1
b. Safety Injection		(See Table 3.5-2, Item 1)			
1.2 Containment Ventilation Isolation					
a. Manual	2	1	1	1	2
b. High Containment Radioactivity	2	1	1	1	2
c. Manual Spray		(See Table 3.5-2, Item 2a)			
d. Safety Injection		(See Table 3.5-2, Item 1)			

TABLE 3.5-3 (Continued)

FUNCTIONAL UNIT	1 TOTAL NO. OF CHANNELS	2 NO. OF CHANNELS TO TRIP*	3 MIN. OPERABLE CHANNELS	4 MIN. DEGREE OF REDUNDANCY	5 OPERATOR ACTION IF CONDITIONS OF COLUMN 3 CANNOT BE MET
2. STEAM LINE ISOLATION					
a. Hi-Hi Steam Flow with Safety Injection	2/loop	1	1	-	Hot Shutdown ***
b. Hi Steam Flow and 2 of 4 Low T_{AVG} with Safety Injection	2/loop	1	1	-	Hot Shutdown ***
c. 20 psi Containment Pressure	3	2	2	1	Hot Shutdown ***
d. Manual	1/loop	1/loop	1/loop	-	Hot Shutdown
3. FEEDWATER LINE ISOLATION					
a. Safety Injection	(See Table 3.5-2, Item 1)				Hot Shutdown ***
b. Hi Steam Generator Level	3/loop	2 in either loop	2/loop	1/loop	Hot Shutdown ***

TABLE 3.5-3 (Continued)

TABLE NOTATION

* If a functional unit is operating with the minimum operable channels, the number of channels to trip the reactor will be column 3 less column 4.

*** If minimum conditions are not met within 24 hours, steps shall be taken to place the unit in cold shutdown conditions.

ACTION STATEMENTS

ACTION 1 With the number of operable channels one less than the Total Number of Channels, restore the inoperable channel to operable status within 48 hours or be in at least hot shutdown within the next 6 hours and in cold shutdown within the following 30 hours.

ACTION 2 With less than the Minimum Channels operable, operation may continue provided the containment purge and exhaust valves are maintained closed.

TABLE 3.5-4
ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	TOTAL NO. OF CHANNELS	MINIMUM CHANNELS OPERABLE
1. Pressurizer Water Level*	3	2
2. Auxiliary Feedwater Flow Rate****	2 per pump	1 per pump
3. Reactor Coolant System Subcooling Margin Monitor**	2	1
4. PORV Position Indicator***	2/valve	1/valve
5. PORV Block Valve Position Indicator*	1/valve	0
6. Safety Valve Position Indicator***	2/valve	1/valve

*Emergency Power Supply Requirements for Pressurizer Indicators - NUREG 0578 Item 2.1.1
**Instrumentation for Detection of Inadequate Core Cooling - NUREG 0578 Item 2.1.3.b
***Direct Indication of Power Operated Relief Valve and Safety Valve Position - NUREG 0578 item 2.1.3.a. Two channels include a primary detector and thermocouples as the backup detector.
****Auxiliary Feedwater Flow Indication to Steam Generator NUREG 0578 item 2.1.7.b

TABLE 3.5-5

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES*
1. SAFETY INJECTION AND FEEDWATER ISOLATION		
a. Manual Initiation	Not Applicable	Not Applicable
b. High Containment Pressure	$\leq$ 5.0 psig	$\leq$ 6.0 psig
c. Low Pressurizer Pressure	$\geq$ 1723 psig	$\geq$ 1715 psig
d. Low Steam Line Pressure	$\geq$ 514 psig	$\geq$ 500 psig
2. CONTAINMENT SPRAY		
a. Manual Initiation	Not Applicable	Not Applicable
b. High-High Containment Pressure	$\leq$ 28 psig	$\leq$ 30 psig
3. CONTAINMENT ISOLATION		
a. Containment Isolation		
1. Manual	Not Applicable	Not Applicable
2. From Safety Injection Automatic Actuation Logic	Not Applicable	Not Applicable
b. Containment Ventilation Isolation		
1. Manual	Not Applicable	Not Applicable
2. High Containment Radioactivity	NOTE 3	Not Applicable
3. From Safety Injection	Not Applicable	Not Applicable
4. Manual Spray	Not Applicable	Not Applicable

TABLE 3.5-5 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES*
4. STEAM LINE ISOLATION		
a. Manual	Not Applicable	Not Applicable
b. High Containment Pressure	$\leq$ 18 psig	$\leq$ 20 psig
c. High Steam Flow , Coincident with Low T_{avg} and SI	dp corresponding to $\leq 0.49 \times 10^6$ lbs/hr at 755 psig $T_{avg} \geq 545°F$	dp corresponding to $\leq 0.55 \times 10^6$ lbs/hr at 755 psig $T_{avg} \geq 543°F$,
d. High-High Steam Line Flow Coincident with SI	dp corresponding to $\leq 3.6 \times 10^6$ lbs/hr at 755 psig	dp corresponding to $\leq 3.7 \times 10^6$ lbs/hr at 755 psig
5. FEED WATER ISOLATION		
a. High Steam Generator Water Level	$\leq$ 67% of narrow range instrument span each steam generator	$\leq$ 68% of narrow range instrument span each steam generator
6. AUXILIARY FEEDWATER		
a. Low-Low Steam Generator Water Level	$\geq$ 17% of narrow range instrument span each steam generator	$\geq$ 16% of narrow range instrument span each steam generator. See Note 1.
b. From Safety Injection	N.A.	N.A.
c. Loss of 4 kV Voltage (Start TAFP)	62% of 4160 volts Note 2	Note 2
d. Feedwater Pump Breakers Open (start MAFP)	Not Applicable	Not Applicable

TABLE 3.5-5 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
7. LOSS OF VOLTAGE		
a. 480 V Safeguards Bus Under-voltage (Loss of Voltage)	see Figure 2.3-1	(Effective No Later Than Completion of the Spring 1982 Outage. See NRC letter dated May 6, 1981.
b. 480 V Safeguards Bus Under-voltage (Degraded Voltage)	see Figure 2.3-1	(Effective No Later Than Completion of the Spring 1982 Outage. See NRC letter dated May 6, 1981.
8. ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INTERLOCKS		
a. Pressurizer Pressure, (block, unblock SI)	$\leq$ 2000 psig	$\leq$ 2010 psig

Note 1: A positive 11% error has been included in the setpoint to account for errors which may be introduced into the steam generator level measurement system at a containment temperature of 286°F as determined by an evaluation performed on temperature effects on level systems as required by IE Bulletin 79-21.

Note 2: This setpoint value is from inverse time curve for CVT relay (406C883) with tap setting of 82 volts and time dial setting of 1. Delay at 62% voltage is 3.6 seconds. The allowable values are ±5% of the trip setpoint.

Note 3: The trip setpoints for containment ventilation isolation while purging shall be established to correspond to the limits of 10 CFR Part 20 for unrestricted areas. The setpoints are determined procedurally in accordance with Technical Specification 3.9.2 by calculating effluent monitor count rate limits, which take into account appropriate factors for detector calibration, ventilation flow rate, and average site meteorology.

*Allowable Values are those values assumed in accident analysis.

3.6 Containment System

Applicability:

Applies to the integrity of reactor containment.

Objective:

To define the operating status of the reactor containment for plant operation.

Specification:

3.6.1 Containment Integrity

a. Except as allowed by 3.6.3 containment integrity shall not be violated unless the reactor is in the cold shutdown condition.

b. The containment integrity shall not be violated when the reactor vessel head is removed unless the boron concentration is greater than 2000 ppm.

c. Positive reactivity changes shall not be made by rod drive motion or boron dilution whenever the containment integrity is not intact unless the boron concentration is greater than 2000 ppm.

3.6.2 Internal Pressure

If the internal pressure exceeds 3 psig or the internal vacuum exceeds 2.0 psig, the condition shall be corrected within 24 hours or the reactor rendered subcritical.

3.6.3 Containment Isolation Valves

3.6.3.1 With one or more of the isolation valve(s) specified in Table 3.6-1 inoperable, maintain at least one isolation valve operable in each affected penetration that is open and either:

a. Restore the inoperable valve(s) to operable status within 4 hours, or

b. Isolate each affected penetration within 4 hours by use of at least one deactivated automatic valve secured in the isolation position, or

c. Isolate each affected penetration within 4 hours by use of at least one closed manual valve or blind flange, or

d. Be in at least hot shutdown within the next 6 hours and in cold shutdown within the following 30 hours.

Isolation valves are inoperable from a leakage standpoint if the leakage is greater than that allowed by 10 CFR 50 Appendix J.

Basis:

The reactor coolant system conditions of cold shutdown assure that no steam will be formed and hence there would be no pressure buildup in the containment if the reactor coolant system ruptures.

The shutdown margins are selected based on the type of activities that are being carried out. The (2000 ppm) boron concentration provides shutdown margin which precludes criticality under any circumstances. When the reactor head is not to be removed, a cold shutdown margin of 1%Δk/k precludes criticality in any occurrence.

Regarding internal pressure limitations, the containment design pressure of 60 psig would not be exceeded if the internal pressure before a major loss-of-coolant accident were as much as 6 psig.[1] The containment is designed to withstand an internal vacuum of 2.5 psig.[2] The 2.0 psig vacuum is specified as an operating limit to avoid any difficulties with motor cooling.

References:

(1) FSAR - Section 14.3.5

(2) FSAR - Section 5.5

Amendment No. 42

TABLE 3.6-1

CONTAINMENT ISOLATION VALVES

PENT. NO.	IDENTIFICATION/DESCRIPTION	PRIMARY ISOLATION BOUNDARY	MAXIMUM ISOLATION TIME *(SEC)	SECONDARY ISOLATION BOUNDARY	MAXIMUM ISOLATION TIME *(SEC)
29	Fuel transfer tube	flange	NA	(1)	NA
100	charging line to "B" loop	CV 370B	NA	(2)	NA
101	SI Pump 1B discharge	CV 889B CV 870B	NA NA	(5) (5)	NA NA
102	Alternate charging to "A" cold leg	CV 383B	NA	(2)	NA
103	Construction Fire Service Water	welded flange	NA	MV 5129	NA
105	Containment Spray Pump 1A	CV 862A	NA	(3)	NA
106	"A" Reactor Coolant Pump (RCP) seal water inlet	CV 304A	NA	(2)	NA
107	Sump A discharge to Waste Holdup Tank	AOV 1728	60	AOV 1723	60
108	RCP seal water out and excess letdown to VCT	MOV 313	60	(4)	NA
109	Containment Spray Pump 1B	CV 862B	NA	(3)	NA
110	"B" RCP seal water inlet	CV 304B	NA	(2)	NA
110	SI test line	MV 879	NA	(5)	NA
111	RHR to "B" cold leg	MOV 720(20)	NA	(6)	NA
112	letdown to Non-regen. Heat exchanger	AOV 371	60	MV 204A MV 820 (14)(17)	NA
113	SI Pump 1A discharge	CV 889A CV 870A	NA NA	(5) (5)	NA NA
120	Nitrogen to Accumulators	AOV 846	60	CV 8623	NA
120	Pressurizer Relief Tank (PRT) to Gas Analyzer (GA)	AOV 539	60	MV 546(7)	NA

PENT. NO.	IDENTIFICATION/DESCRIPTION	PRIMARY ISOLATION BOUNDARY	MAXIMUM ISOLATION TIME *(SEC)	SECONDARY ISOLATION BOUNDARY	MAXIMUM ISOLATION TIME *(SEC)
121	Nitrogen to PRT	CV 528	NA	MV 547(8)	NA
121	Reactor Makeup water to PRT	CV 529	NA	AOV 508	60
121	Cont. Press. transmitter PT-945 (10)	PT 945	NA	MV 1819A	NA
121	Cont. Press. transmitter PT-946 (10)	PT 946	NA	MV 1819B	NA
123	Reactor Coolant Drain Tank (RCDT) to GA	AOV 1789	60	MV 1655(7)	NA
124	Excess letdown supply and return to heat exchanger	AOV 745 CV 743	60 NA	(11) (11)	NA NA
124	Post Accident air sample "C" fan	MV 1569 MV 1572	NA NA	MV 1571 MV 1574	NA NA
125	Component Cooling Water (CCW) from 1B RCP	MOV 759B	NA	(12)	NA
126	CCW from 1A RCP	MOV 759A	NA	(12)	NA
127	CCW to 1A RCP	CV 750A	NA	MOV 749A	60
128	CCW to 1B RCP	CV 750B	NA	MOV 749B	60
129	RCDT & PRT to Vent Header	AOV 1787 CV 1713	 NA	AOV 1786	60
130	CCW to reactor support cooling	MOV 813	60	(19)	NA
131	CCW to reactor support cooling	MOV 814	60	(19)	NA
132	Depressurization at power	AOV 7970	60	AOV 7971	60
140	RHR pump suction from "A" Hot leg	MOV 701(20)	NA	(6)	NA
141	RHR-#1 pump suction from Sump B	MOV 850A(13)	NA	MOV 851A(13)	NA
142	RHR-#2 pump suction from Sump B	MOV 850B(13)	NA	MOV 851B(13)	NA
143	RCDT pump suction	AOV 1721	60	AOV 1003A AOV 1003B	60 60
201	Reactor Compart. cooling Unit A & B	MV 4757(16) MV 4636(16)	NA NA	(11) (11)	NA NA
202	"B" Hydrogen recombiner (pilot & main)	MV 1076B MV 1084B	NA NA	SOV IV-3B SOV IV-5B	NA Normally Closed NA Normally Closed

PENT. NO.	IDENTIFICATION/DESCRIPTION	PRIMARY ISOLATION BOUNDARY	MAXIMUM ISOLATION TIME *(SEC)	SECONDARY ISOLATION BOUNDARY	MAXIMUM ISOLATION TIME *(SEC)
203	Contain. Press. transmitter PT-947 & 948	PT 947	NA	MV 1819C	NA
		PT 948	NA	MV 1819D	NA
203	Post accident air sample to "B" fan	MV 1563	NA	MV 1565	NA
		MV 1566	NA	MV 1568	NA
204	Purge Supply Duct	AOV 5870	5	AOV 5869	5
205	Hot leg loop sample	AOV 966C	60	MV 956D(14)	NA
206	Przr. liquid space sample	AOV 966B	60	MV 956E(14)	NA
206	"A" S/G sample	AOV 5735	60	MV 5733(7)	NA
207	Przr. Steam space sample	AOV 966A	60	MV 956F	NA
207	"B" S/G sample	AOV 5736	60	MV 5734(7)	NA
209	Reactor Compart. cooling Units A & B	MV 4758(16)	NA	(11)	NA
		MV 4635(16)	NA	(11)	NA
210	Oxygen makeup to A & B recombiners	MV 1080A	NA	SOV IV-2A	NA Normally Closed
				SOV IV-2B	NA Normally Closed
300	Purge Exhaust Duct	AOV 5878	5	AOV 5879	5
301	Aux. steam supply to containment	MV 6151	NA	MV 6165(15)	NA
303	Aux. steam condensate return	MV 6175	NA	MV 6152(15)	NA
304	"A" Hydrogen recombiner (pilot and main)	MV 1084A	NA	SOV IV-5A	NA Normally Closed
		MV 1076A	NA	SOV IV-3A	NA Normally Closed
305	Radiation Monitors R-11, R-12 & R-10A Auto Inlet Isol.	AOV 1597	60	MV 1596	NA
305	R-11, R-12 & R-10A Outlet	CV 1599	NA	AOV 1598	60
305	Post Accident air sample (containment)	MV 1554	NA	MV 1556	NA
		MV 1557	NA	MV 1559	NA
		MV 1560	NA	MV 1562	NA
307	Fire Service Water (18)	CV 9229	NA	AOV 9227	isolation criteria will be determined in the future

PENT. NO.	IDENTIFICATION/DESCRIPTION	PRIMARY ISOLATION BOUNDARY	MAXIMUM ISOLATION TIME *(SEC)	SECONDARY ISOLATION BOUNDARY	MAXIMUM ISOLATION TIME *(SEC)
308	Service Water to "A" fan cooler	MV 4627(16)	NA	(11)	NA
309	leakage test depressurization	flange	NA	MOV 7445	NA Normally Closed
310	Service Air to Contain.	CV 7226	NA	MV7141	NA
310	Instrument Air to Contain.	CV 5393	NA	AOV 5392	60
311	Service Water from "B" fan cooler	MV 4630(16)	NA	(11)	NA
312	Service Water to "D" fan cooler	MV 4642(16)	NA	(11)	NA
313	leakage test depressurization	flange	NA	MOV 7444	NA Normally Closed
315	Service Water from "C" fan cooler	MV 4643(16)	NA	(11)	NA
316	Service Water to "B" fan cooler	MV 4628(16)	NA	(11)	NA
317	leakage test supply	flange	NA	MOV 7443	NA Normally Closed
318	Dead weight tester	tubing cap	NA	MV 549B	NA
319	Service Water from "A" fan cooler	MV 4629(16)	NA	(11)	NA
320	Service water to "C" fan cooler	MV 4641(16)	NA	(11)	NA
321	A S/G Blowdown	AOV 5738	60	MV 5701(7)	NA
322	B S/G Blowdown	AOV 5737	60	MV 5702(7)	NA
323	Service Water from "D" fan cooler	MV 4644(16)	NA	(11)	NA
324	Demineralized water to Containment	CV 8419	NA	AOV 8418	60
332	Cont. Press. Trans. PT-944, 949 & 950	PT 944 PT 949 PT 950	NA NA NA	MV 1819G MV 1819F MV 1819E	NA NA NA
332	Leakage test instrumentation lines	Cap Cap Cap	NA NA NA	MV 7448 MV 7452 MV 7456	NA NA NA
401	Main steam from A S/G	NA**	NA	NA	NA
402	Main steam from B S/G	NA**	NA	NA	NA

PENT. NO.	IDENTIFICATION/DESCRIPTION	PRIMARY ISOLATION BOUNDARY	MAXIMUM ISOLATION TIME *(SEC)	SECONDARY ISOLATION BOUNDARY	MAXIMUM ISOLATION TIME *(SEC)	
403	Feedwater line to A S/G		NA**	NA	NA	NA
404	Feedwater line to B S/G		NA**	NA	NA	NA
1000	Personnel Hatch	NA	NA	NA	NA	
2000	Equipment Hatch	NA	NA	NA	NA	

*The maximum isolation time does not include diesel start time.
**The MSIVs and feedwater isolation valves are not considered to be containment isolation valves for the purpose of leak testing. The containment boundary is the steam generator secondary side and tubes.

MV - Manual Valve
MOV - Motor Operated Valve
AOV - Air Operated Valve
CV - Check Valve
SOV - Solenoid Operated Valve

NOTES

(1) The end of the fuel transfer tube inside containment is closed by a double-gasketed blind flange, to prevent leakage of spent fuel pit water into the containment during plant operation. This flange also serves as protection against leakage from the containment following a loss of coolant accident. The space between these gaskets can also be pressurized by the penetration test system. (FSAR 5.2.2 pg. 5.2.2-3)

(2) Incoming lines connected to closed systems outside containment are provided with at least one check valve or normally closed isolation valve located inside containment. (FSAR 5.2.2 pg 5.2.2-2)

(3) The Containment Spray System is a closed system outside containment provided with a single containment isolation valve (FSAR Table 5.2.2-1 and Figure 5.2.2-8).

(4) The single remotely controlled, motor operated containment isolation valve is normally open. The seal water return line is not directly connected to the Reactor Coolant System. A second automatic isolation barrier is provided by the closed system consisting of the volume control tank and connecting piping.

(5) The Safety Injection system is a closed system outside containment provided with a single containment isolation valve (FSAR Table 5.2.2-1 and Figure 5.2.2-9). Connections of the test line with other lines inside containment are all missile protected and upstream of check valves connecting to the RCS. The SI system is in operation following a LOCA and pressurized to a pressure higher than that in containment.

(6) The RHR system is a closed system outside containment provided with one normally closed, missile protected containment isolation valve inside containment. In addition, a second normally closed valve is provided inside the missile barrier (FSAR Table 5.2.2-1 and Figure 5.2.2-2, see also ANSI-N271-1976).

(7) Normally operating outgoing lines not connected to the Reactor Coolant System and not protected against missiles throughout their length inside containment are provided with at least one automatically operated trip valve or one remotely operated stop valve located outside containment. Manual isolation valves in series with the trip or remote operated valves are also provided outside the containment (FSAR 5.2.2 pg. 5.2.2-1a).

(8) See FSAR Table 5.2.2-1 and Figure 5.2.2-1.

(9) Incoming lines connected to open systems outside the containment are provided with a check valve located inside containment, and a remote operated valve or check valve and remote operated valve located outside containment. (FSAR 5.2.2 pg. 5.2.2-2)

(10) The pressure transmitter provides a boundary.

(11) Normally operating incoming and outgoing lines which are connected to closed systems inside containment and protected against missiles throughout their length, are provided with at least one manual isolation valve outside containment (FSAR 5.2.2 pg. 5.2.2-2).

(12) The single remotely controlled containment isolation valve is normally open and motor operated. The cooling water return line is not directly connected to the reactor coolant system and, should remain open while the coolant pump is running. A second automatic isolation barrier is provided by the component cooling water loop, a closed system. (FSAR 5.2.2 pg. 5.2.2-1a)

(13) See FSAR Table 5.2.2-1 and Figure 5.2.2-2. Sump lines are in operation and filled with fluid following an accident. Containment leakage testing is not required. The valves are subjected to RHR system hydrostatic test.

(14) Normally operating outgoing lines connected to the Reactor Coolant System are provided with at least one automatically operated trip valve and one manual isolation valve in series located outside the containment. In addition to the isolation valves, each line connected to the Reactor Coolant System is provided with a remote operated root valve located near its connection to the Reactor Coolant System. (FSAR 5.2.2 pg. 5.2.2-1)

(15) See FSAR Table 5.2.2-1 and Figure 5.2.2-17.

(16) The Service Water system operates at a pressure higher than the containment accident pressure and is missile protected inside containment. Therefore, these valves are used for flow control only and need not be leak tested.

(17) A manual valve outside containment in series with an automatic valve is provided for normally operating outgoing RCS lines (FSAR pg. 5.2.2-1).

(18) Installation of this penetration and valving is scheduled for 1981.

(19) See FSAR Table 5.2.2-1 and Figure 5.2.2-16.

(20) Containment leakage testing is not required per L. D. White, Jr. letter to Dennis L. Ziemann, USNRC dated September 21, 1978.

4.0 SURVEILLANCE REQUIREMENTS

Specified intervals may be adjusted plus or minus 25% to accommodate normal test schedules.

4.1 Operational Safety Review

Applicability:

Applies to items directly related to safety limits and limiting conditions for operation.

Objective:

To specify the minimum frequency and type of surveillance to be applied to plant equipment and conditions.

Specification:

4.1.1 Calibration, testing, and checking of analog channel and testing of logic channel shall be performed as specified in Table 4.1-1.

4.1.2 Equipment and sampling tests shall be conducted as specified in Table 4.1-2.

4.1.3 Each accident monitoring instrumentation channel shall be demonstrated operable by performance of the channel check and channel calibration operations at the frequencies shown in Table 4.1-3.

Basis:

Check

Failures such as blown instrument fuses, defective indicators, faulted amplifiers which result in "upscale" or "downscale" indication can be easily recognized by simple observation of the functioning of an instrument or system. Furthermore, such failures are, in many cases, revealed

TABLE 4.1-1 (CONTINUED)

	Channel Description	Check	Calibrate	Test	Remarks
25.	Containment Pressure	S	R	M	Narrow range containment pressure (-3.0, +3 psig excluded)
26.	Steam Generator Pressure	S	R	M	
27.	Turbine First Stage Pressure	S	R	M	
28.	Emergency Plan Radiation Instruments	M	R	M	
29.	Environmental Monitors	M	N.A.	N.A.	
30.*	Loss of Voltage/Degraded Voltage 480 Volt Safe-guards Bus	N.A.	R	M	
31.	Trip of Main Feedwater Pumps	N.A.	N.A.	R	
32.	Steam Flow	S	R	M	
33.	T_{AVG}	S	R	M	

*Effective 30 days after completion of necessary modifications and no later than completion of the Spring 1982 refueling outage.

TABLE 4.1-3

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

	INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL TEST
1.	Pressurizer Water Level*	See Table 4.1-1	See Table 4.1-1	NA
2.	Auxiliary Feedwater Flow Rate****	See Section 4.8.1	R	NA
3.	Reactor Coolant System Subcooling Margin Monitor**	M	R	NA
4.	PORV Position Indicator*** (Primary Detector)	M	NA	R
5.	PORV Position Indicator*** (Thermocouples-Backup Detector)	M	R	NA
6.	PORV Block Valve Position Indicator*	M	NA	R
7.	Safety Valve Position Indicator*** (Primary Detector)	M	R	NA
8.	Safety Valve Position Indicator*** (Thermocouples-Backup Detector)	M	R	NA

*Emergency Power Supply Requirements for Pressurizer Level Indicators - NUREG 0578 Item 2.1.1
**Instrumentation for Detection of Inadequate Core Cooling - NUREG 0578 Item 2.1.3.b
***Direct Indication of Power Operated Relief Valve and Safety Valve Position - NUREG 0578 item 2.1.3.a
****Auxiliary Feedwater Flow Indication to Steam Generator NUREG 0578 item 2.1.7.b

4.3 REACTOR COOLANT SYSTEM

Applicability:

Applies to surveillance of the reactor coolant system and its components.

Objective:

To ensure operability of the reactor coolant system and its components.

Specifications:

4.3.1 Reactor Vessel Material Surveillance Testing

4.3.1.1 The reactor vessel material surveillance testing program is designed to meet the requirements of Appendix H to 10 CFR Part 50. This program consists of the metallurgical specimens receiving the following test: tensile, charpy impact and the WOL test. These tests of the Radiation Capsule Specimens shall be performed as follows:

Capsule	Time Tested
V	End of 1st core cycle
R	End of 3rd core cycle
T	10 years, at nearest refueling
P	20 years, at nearest refueling
S	30 years, at nearest refueling
N	Standby

4.3.1.2 The report of the Reactor Vessel Material Surveillance shall be written as a Summary Technical Report as required by Appendix H to 10 CFR Part 50.

4.3.2 Pressurizer

4.3.2.1 The pressurizer water level shall be verified to be within its limits at least once per 12 hours during power operation and hot shutdown.

Amendment No. ~~12~~, 42

4.3.3 Check Valves

4.3.3.1 Leakage testing of check valves 853A, 853B, 867A, 867B, 878G and 878J shall be accomplished prior to criticality following (1) refueling, (2) cold shutdown, and (3) maintenance, repair or replacement work on the valves. Leakage may be measured indirectly from the performance of pressure indicators, system volume measurements or by direct measurement. Minimum test differential pressure shall be greater than 150 psid. See 4.3.3.4 for allowable leakage rates.

4.3.3.2 Check valves 878G and 878J will be tested for leakage following each safety injection flow test. Minimum test differential pressure shall be greater than 150 psid. See 4.3.3.4 for allowable leakage rates.

4.3.3.3 Motor-operated valves 878A and 878C and check valves 877A, 877B, 878F, and 878H shall be tested at the first refueling outage following the date of this order* to individually assure integrity of at least two of the three pressure boundaries in each hot leg high-head safety injection path. Testing shall also be performed after any opening of either motor-operated valve and at a minimum, once every 40 months. Opening of the motor-operated valves, and testing, are to be performed at a test pressure less than that of the lowest design pressure of any portion of the high-head safety injection system which may be pressurized during the test. Minimum test differential pressure shall be greater than 150 psid. See 4.3.3.4 for allowable leakage rates.

4.3.3.4 Allowable check valve leakage rates are as follows:

(a) Leakage rates less than or equal to 1.0 gpm are considered acceptable.

(b) Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are considered acceptable if the latest measured rate has not exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

(c) Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are considered unacceptable if the latest measured rate exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

(d) Leakage rates greater than 5.0 gpm are considered unacceptable.

*NRC Order dated April 20, 1981

4.3.4 Relief Valves

4.3.4.1 Each PORV shall be demonstrated operable at least once per 18 months by performance of a CHANNEL CALIBRATION.

4.3.4.2 Except during cold and refueling shutdown each block valve shall be demonstrated operable at least once per 92 days by operating the valve through one complete cycle of full travel unless the valve is already closed.

Basis:

This material surveillance program monitors changes in the fracture toughness properties of ferritic materials in the reactor vessel beltline region of the reactor resulting from exposure to neutron irradiation and the thermal environment. The test data obtained from this program will be used to determine the conditions under which the reactor vessel can be operated with adequate margins of safety against fracture through out its service life.

The surveillance requirements on pressurizer equipment will assure proper performance of the pressurizer function and give early indication of malfunctions.

b. The local leakage rate shall be measured for each of the following components:

   i. Containment penetrations that employ resilient seals, gaskets or sealant compounds, piping penetrations with expansion bellows and electrical penetrations with flexible metal seal assemblies.

   ii. Air lock and equipment door seals.

   iii. Fuel transfer tube.

   iv. Isolation valves on the testable fluid systems lines penetrating the containment.

   v. Other containment components, which require leak repair in order to meet the acceptance criterion for any integrated leakage rate test.

4.4.2.2 Acceptance Criterion

The total leakage from all penetrations and isolation valves shall not exceed 0.60La.

4.4.2.3 Corrective Action

a. If at any time it is determined that the total leakage from all penetrations and isolation valves exceeds 0.60La, repairs shall be initiated immediately.

b. If repairs are not completed and conformance to the acceptance criterion of 4.4.2.2 is not demonstrated within 48 hours, the reactor shall be shutdown and depressurized until repairs are effected and the local leakage meets this acceptance criterion.

4.4.2.4 Test Frequency

a. Except as specified in b., c., and d. below, individual penetrations and containment isolation valves shall be tested during each reactor shutdown for refueling, or other convenient intervals, but in no case at intervals greater than two years.

b. The containment equipment hatch and fuel transfer tube shall be tested at each refueling shutdown or after each use, if that be sooner.

c. The containment air locks shall be tested at intervals of no more than six months by pressurizing the space between the air lock doors. In addition, following opening of the air lock door during the interval, a test shall be performed by pressurizing between the dual seals of each door opened, within 48 hours of the opening, unless the reactor was in the cold shutdown condition at the time of the opening or has been subsequently brought to the cold shutdown condition. A test shall also be performed by pressurizing between the dual seals of each door within 48 hours of leaving the cold shutdown condition, unless the doors have not been opened since the last test performed either by pressurizing the space between the air lock doors or by pressurizing between the dual door seals.

d. Within 24 hours after each closing when containment integrity is required, except when being used for multiple cycles and then at least once per 72 hours, each containment purge isolation valve shall be tested to verify that when the measured leakage rate is added to the leakage rates determined for all other Type B and C penetrations, the combined leakage rate is less than or equal to 0.60 La.

4.4.3 Recirculation Heat Removal Systems

4.4.3.1 Test

a. the portion of the residual heat removal system that is outside the containment shall either be tested by use in normal operation or hydrostatically tested at 350 psig at the interval specified in 4.4.3.4.

b. Suction piping from containment sump B to the reactor coolant drain tank pump and the discharge piping from the pumps to the residual heat removal system shall be hydrostatically tested at no less than 100 psig at the interval specified in 4.4.3.4.

the tendon containing 6 broken wires) shall be inspected. The acceptance criterion then shall be no more than 4 broken wires in any of the additional 4 tendons. If this criterion is not satisfied, all of the tendons shall be inspected and if more than 5% of the total wires are broken, the reactor shall be shutdown and depressurized.

4.4.4.2 Pre-Stress Confirmation Test

a. Lift-off tests shall be performed on the 14 tendons identified in 4.4.4.1a above, at the intervals specified in 4.4.4.1b. If the average stress in the 14 tendons checked is less than 144,000 psi (60% of ultimate stress), all tendons shall be checked for stress and retensioned, if necessary, to a stress of 144,000 psi.

b. Before reseating a tendon, additional stress (6%) shall be imposed to verify the ability of the tendon to sustain the added stress applied during accident conditions.

4.4.5 Containment Isolation Valves

4.4.5.1 Each isolation valve specified in Table 3.6-1 shall be demonstrated to be operable in accordance with the Ginna Station Pump and Valve Test Program submitted in accordance with 10 CFR 50.55a.

4.4.6 Containment Isolation Response

4.4.6.1 Each containment isolation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION, and CHANNEL FUNCTIONAL TEST operations for the MODES and at the frequencies shown in Table 4.1-1.

4.4.6.2 The RESPONSE TIME of each containment isolation function shall be demonstrated to be within the limit at least once per 18 months. Each test shall include at least one channel per function such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific function as shown in the "Total No. of Channels" Column of Table 3.5-3. The response time limit shown on Table 3.6-1 does not include diesel generator starting times but does include valve travel times for all valves that change position. The times determined in independent tests, such as electronic response of portions of the initiating circuitry and valve travel times, may be combined to determine the total function response time.

Basis:

The containment is designed for an accident pressure of 60 psig.(1) While the reactor is operating, the internal environment of the containment will be air at approximately atmospheric pressure and a maximum temperature of about 120°F. With these initial conditions, the temperature of the steam-air mixture at the peak accident pressure of 60 psig is calculated to be 286°F.

The pre-stress confirmation test provides a direct measure of the load-carrying capability of the tendon.

If the surveillance program indicates by extensive wire breakage or tendon stress relation that the pre-stressing tendons are not behaving as expected, the situation will be evaluated immediately. The specified acceptance criteria are such as to alert attention to the situation well before the tendon load-carrying capability would deteriorate to a point that failure during a design basis accident might be possible. Thus the cause of the incipient deterioration could be evaluated and corrective action studied without need to shut down the reactor. The containment is provided with two readily removable tendons that might be useful to such a study. In addition, there are 40 tendons, each containing a removable wire which will be used to monitor for possible corrosion effects.

Operability of the containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment. Performance of cycling tests and verification of isolation times are covered by the Pump and Valve Test Program. Compliance with Appendix J to 10 CFR 50 is addressed under local leak testing requirements.

References:

(1) FSAR Section 5.1.2.3

(2) FSAR Section 5.1.2

(3) FSAR Section 14.3.5

(4) FSAR Table 6.2-8

(5) FSAR Section 6.2.3

(6) FSAR Page 5.1.2-28

(7) North-American-Rockwell Report 550-x-32, Autonetics Reliability Handbook, February 1963.

(8) FSAR Page 5.1.2-28

4.8.5 Except during cold or refueling shutdowns, the suction, discharge, and cross-over motor operated valves for the Standby Auxiliary Feedwater pumps shall be exercised at intervals not to exceed one month.

4.8.6 These tests shall be considered satisfactory if control board indication and subsequent visual observation of the equipment demonstrate that all components have operated properly. These tests shall be performed prior to exceeding 5% power during a startup if the time since the last test exceeds one month.

4.8.7 At least once per 18 months, control of the standby auxiliary feed system pumps and valves from the control room will be demonstrated.

4.8.8 At least once per 18 months during shutdown

a. Verify that each automatic valve in the flow path for each auxiliary feedwater pump actuates to its correct position upon receipt of each auxiliary feedwater actuation test signal.

b. Verify that each auxiliary feedwater pump starts as designed automatically upon receipt of each auxiliary feedwater actuation test signal.

4.8.9 Each instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION, and CHANNEL FUNCTIONAL TEST operations for the MODES and at the frequencies shown in Table 4.1-1.

4.8.10 The RESPONSE TIME of each function shall be demonstrated to be within the limit of 10 minutes at least once per 18 months. Each test shall include at least one channel per function such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific ESFAS function as shown in the "Total No. of Channels" Column of Table 3.5-2. The times determined in independent tests, such as electronic response of portions of the initiating circuitry and valve travel times, may be combined to determine the total function response time.

Basis

The monthly testing of the auxiliary feedwater pumps by supplying feedwater to the steam generators will verify their ability to meet design. The flow rates will be measured at a simulated steam generator pressure of 1100 psia. The capacity of any one of the three auxiliary feedwater pumps is sufficient to meet decay heat removal requirements. Proper functioning of the steam turbine admission valve and the feedwater pumps start will demonstrate the integrity of the steam drive pump.

Monthly testing of the Standby Auxiliary Feedwater pumps by supplying water from a condensate supply tank to the steam generators will verify their ability to meet design. The flow rate will be measured at a simulated steam generator pressure of 1100 psia.

The Standby Auxiliary Feedwater pumps would be used only if all three auxiliary feedwater pumps were unavailable. One of the two standby pumps would be sufficient to meet decay heat removal requirements. Proper functioning of the suction valves from the service water system, the discharge valves, and the crossover valves will demonstrate their operability. The operability of the standby AFW pump flow paths between the pumps and the steam generators is demonstrated using water from the test tank. Testing of the main AFW pumps using their primary source of water supply will verify the operability of the AFW flow path.

Verification of correct operation will be made both from instrumentation within the main control room and by direct visual observation of the pumps.

<u>References</u>:

FSAR - Section 10.4

FSAR - Section 14.1.9

FSAR - Section 14.2.5

"Effects of High Energy Pipe Breaks Outside the Containment Building" submitted by letter dated November 1, 1973 from K. W. Amish, Rochester Gas and Electric Corporation to A. Giambusso, Deputy Director for Reactor Projects, U.S. Atomic Energy Commission.

Amendment No. ~~29~~, 42

R.E. GINNA NUCLEAR POWER PLANT
MANAGEMENT ORGANIZATION CHART

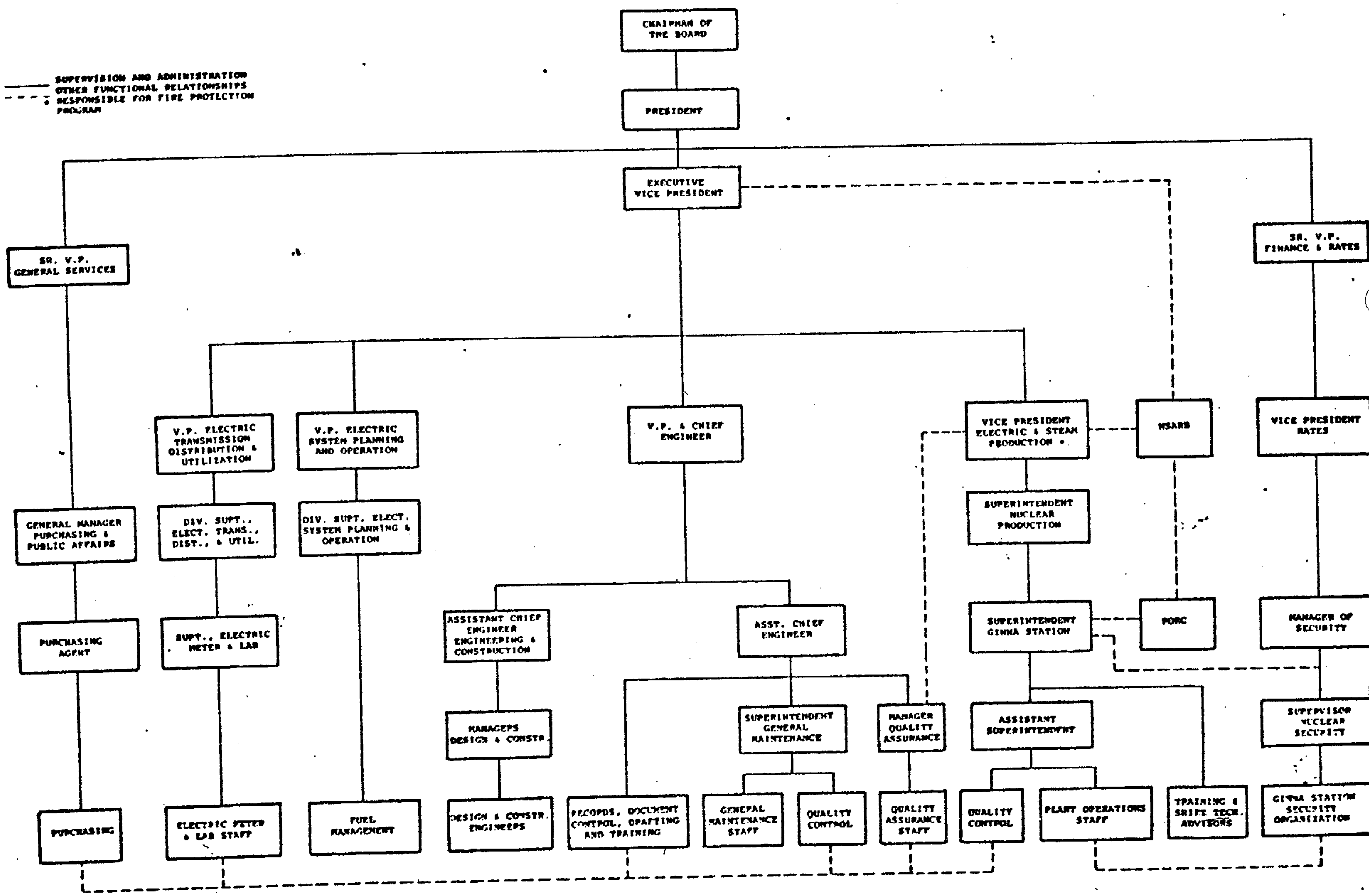

FIGURE 6.2-1

Amendment No. ~~15~~, ~~22~~, ~~35~~, 42

Amendment No. ~~17~~, ~~27~~, 42

ROCHESTER GAS AND ELECTRIC CORPORATION
GINNA STATION ORGANIZATION

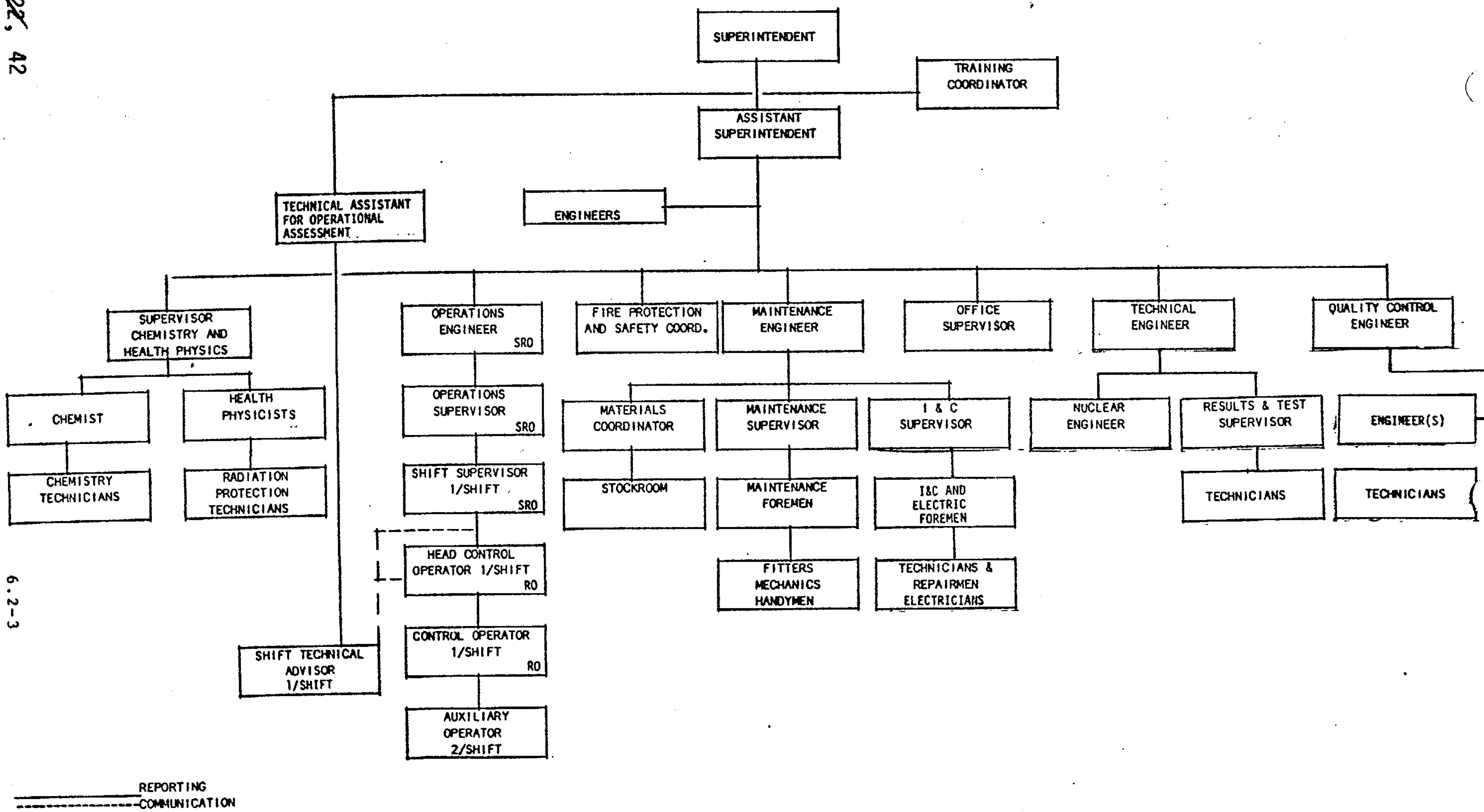

Figure 6.2-2

6.3 STATION STAFF QUALIFICATIONS

6.3.1 Each member of the facility shall meet or exceed the minimum qualifications of ANSI Standard N18.1-1971, "Selection and Training of Nuclear Power Plant Personnel", as supplemented by Regulatory Guide 1.8, September 1975, for comparable positions, except for the Shift Technical Advisor.[1]

6.4 TRAINING

6.4.1 A retraining and replacement training program for the facility staff shall be maintained under the direction of the Training Coordinator and shall meet or exceed the requirements and recommendations of Section 5.5 of ANSI N18.1-1971 and Appendix A of 10 CFR Part 55.

6.4.2 The training program shall meet or exceed NFPA No. 27, 1975 Section 40, except that (1) training for salvage operations need not be provided and (2) the Fire Brigade training sessions shall be held at least quarterly. Drills are considered to be training sessions.

References

1. Ltr. J. Maier (RG&E) to D. Crutchfield (NRC), dated December 30, 1980.

(Next page is 6.5-1)

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

AMENDMENT NO. 42 TO PROVISIONAL OPERATING LICENSE NO. DPR-18

ROCHESTER GAS AND ELECTRIC CORPORATION

R. E. GINNA NUCLEAR POWER PLANT

DOCKET NO. 50-244

I. INTRODUCTION

By letter dated November 13, 1980, Rochester Gas and Electric Corporation (the licensee) proposed changes to the Technical Specifications (TSs) appended to Provisional Operating License No. DPR-18 for the R. E. Ginna Nuclear Power Plant. The changes involve the incorporation of certain of the TMI-2 Lessons Learned Category "A" requirements. The licensee's request is in direct response to the NRC staff's letter dated July 2, 1980.

II. BACKGROUND INFORMATION

By our letter dated September 13, 1979, we issued to all operating nuclear power plants requirements established as a result of our review of the TMI-2 accident. Certain of these requirements, designated Lessons Learned Category "A" requirements, were to have been completed by the licensee prior to any operation subsequent to January 1, 1980. Our evaluation of the licensee's compliance with these Category "A" items was attached to our letter to Rochester Gas and Electric Corporation dated July 7, 1980.

In order to provide reasonable assurance that operating reactor facilities are maintained within the limits determined acceptable following the implementation of the TMI-2 Lessons Learned Category "A" items, we requested that licensees amend their TS to incorporate additional Limiting Conditions of Operation and Surveillance Requirements, as appropriate. This request was transmitted to all licensees on July 2, 1980. Included therein were model specifications that we had determined to be acceptable. The licensee's application is in direct response to our request. Each of the issues identified by the NRC staff and the licensee's response is discussed in the Evaluation below.

III. EVALUATION

2.1.1 Emergency Power Supply Requirements

The pressurizer water level indicators, pressurizer relief and block valves, and pressurizer heaters are important in a post-accident situation. Adequate emergency power supplies add assurance of post-accident functioning of these components. The licensee has the requisite emergency power supplies. The power-operated relief valves receive DC control power from the bus supplied by the battery chargers and thus will receive power from the emergency battery in the event of an emergency. The pressurizer water level indication, block valves, and pressurizer heaters all receive normal power from safeguards buses which can be provided power from the onsite emergency diesel generators. Because of this and the fact that the diesel generators are tested in accordance with existing Technical Specifications, the licensee saw no need to propose additional specifications. We concur and conclude that the emergency power supplies provide reasonable assurance of post-accident functioning of the subject components and are thus acceptable.

2.1.3.a Direct Indication of Valve Position

The licensee has provided a direct indication of power-operated relief valve (PORV) and safety valve position in the control room. These indications are a diagnostic aid for the plant operator and provide no automatic action. The licensee has provided TSs with a 31-day channel check, an 18-month channel test requirement for the PORV indicator and an 18-month channel calibration requirement for the safety valve indicator. Although the channel test was not included as an option in the model specifications, we consider it an acceptable alternative to the channel calibration and we conclude that the specifications are acceptable.

2.1.3.b Instrumentation for Inadequate Core Cooling

The licensee has installed an instrument system to detect the effects of low reactor coolant level and inadequate core cooling. These instruments, subcooling meters, receive and process data from existing plant instrumentation. We previously reviewed this system in our Safety Evaluation dated July 7, 1980. The licensee submitted TSs with a 31-day channel check and an 18-month channel calibration requirement and actions to be taken in the event of component inoperability. We conclude the TSs are acceptable as they meet our July 2, 1980 model TS criteria. However, we note that there is continuing discussion regarding the accuracy and reliability of reactor vessel water level instrumentation. Rochester Gas and Electric Corporation has declined to install such instrumentation until suitable equipment has been developed. This subject is considered to remain an open item.

2.1.4 Diverse Containment Isolation

The licensee has modified the containment isolation system so that diverse parameters will be sensed to ensure automatic isolation of non-essential systems under postulated accident conditions. These parameters are high containment pressure and low pressurizer pressure. We have reviewed this system in our Lessons Learned Category "A" Safety Evaluation dated July 7, 1980 . The modification is such that it does not result in the automatic loss of containment isolation after the containment isolation signal is reset. Reopening of containment isolation would require deliberate operator action. The TSs submitted by the licensee list each affected containment isolation valve and provide for the appropriate surveillance and actions in the event of component inoperability; therefore, we conclude that the TSs are acceptable.

We note, however, that specific reference to the testing of valves prior to their return to service after maintenance, replacement, or repair is not included in the Technical Specifications. This requirement is, however, included in Appendix C of the Ginna Quality Assurance Manual. We consider this acceptable.

2.1.7.a Auto Initiation of Auxiliary Feedwater Systems

The licensee has provided for the automatic initiation of auxiliary (emergency) feedwater flow on loss of normal feedwater flow. The auto-initiation signals used by the licensee include low-low steam generator water level and loss of 4kv voltage. We have previously reviewed the design and installation of this system as part of our Lessons Learned Category "A" program. The circuits are designed to be testable and the design retains the capability of manual actuation from the control room even in the event of failure of the auto-initiating circuitry. The TSs submitted by the licensee list the appropriate components, describe the tests and provide for proper test frequency. The TSs contain appropriate actions in the event of component inoperability; therefore, we conclude that the TSs are acceptable.

2.1.7.b Auxiliary (Emergency) Feedwater Flow Indication

The licensee has installed auxiliary (emergency) feedwater flow indication that meets our testability and vital power requirements. We reviewed this system in our Safety Evaluation dated July 7, 1980. The licensee has proposed a TS with 31-day channel check and 18-month channel calibration requirements. We find this TS acceptable as it meets the criteria of our July 2, 1980 model TS criteria.

2.2.1.b Shift Technical Advisor (STA)

Our request indicated that the TSs related to minimum shift manning should be revised to reflect the augmentation of an STA. The licensee's application would add one STA to each shift to perform the function of accident assessment. The individual performing this function will have a bachelor's degree or equivalent in a scientific or engineering discipline or will be a qualified but non-degreed Senior Reactor Operator. We have found this satisfactory for the short-term, although in the long-term, incumbents in this position must have bachelor's degrees. Part of the STA duties are related to the operating experience review function, and Rochester Gas and Electric Corporation has added the position of Technical Assistant for Operational Assessment, to whom the STA will report in this regard. We have found that these additions will enhance the safety of plant operation and are thus acceptable.

OTHER SPECIFIC COMMENTS REGARDING TECHNICAL SPECIFICATION CHANGES:

In our review of the proposed specifications, we determined that additional items not specifically mentioned above deserve comment. These are:

(1) Specification 2.3.1.3 has been modified to incorporate pressurizer level measurement requirements stated in IE Bulletin 79-21. We have found this acceptable.

(2) Specification 3.5.3 regarding Engineered Safety Feature Actuation Instrumentation, does not incorporate response time surveillance as included in the model TS. The licensee does not have Standard Technical Specifications and the Ginna Technical Specifications do not include response times except as otherwise incorporated in this action for the AFW and Containment Isolation Systems. We have concluded that the lack of these requirements is satisfactory.

(3) Although the required operator actions for items 3.c and 3.e of Table 3.5-2 do not conform to the model TS, we consider them satisfactory. The model TS imply that the channel is totally inoperable, whereas Rochester Gas and Electric takes into account the fact that the channel can be "tripped," thus requiring only a signal from the operable channel to scram the plant.

(4) Although the model TS for item 3.e of Table 3.5-2 would require the start signal for the AFW pumps at any time when power is greater than 0%, RG&E has determined that the actual value should be 5%. This is because at less than 5% power, AFW flow is being controlled to maintain steam generator level (main feed water is not in service) and automatic initiation of full AFW flow would be deleterious. We concur in this assessment and conclude that the modification is acceptable.

(5) As a point of clarification, containment purge and vent valves are included in the Containment Ventilation Isolation unit of Table 3.5-3.

(6) RG&E has not included channel functional tests for the PORVs because of the potential for serious error during such testing at the Ginna plant. It must first be recognized that the safe position of these valves is shut; RG&E maintains that channel functional testing of the valve is therefore unnecessary. Also, in order to perform the test, the operator must manually control the pressurizer, the control bank of heaters must be removed from service, and manual control of pressurizer spray is necessary. We concur that the benefit to be gained from such an evolution does not outweigh the risk involved and thus that the exception is justified and acceptable.

(7) Items 4.c and 4.d of Technical Specification Table 3.5-5 are not included in the surveillance requirements of Technical Specification Table 4.1-1. RG&E has agreed to submit, by March 16, 1981, applicable changes to the specifications. In the interim, the surveillance is being performed as required by plant procedures. We find this acceptable.

(8) RG&E has determined there are no bypass functions to be included in Specification 4.4.6 (Containment Isolation Response) and 4.8.9 (AFW initiation).

(9) Changes to Figure 6.2-2 include those made to reflect the current Ginna Station organization and include the addition of an Office Supervisor, a Materials coordinator, and the plant stockroom. None of these changes are expected to have an impact on the safe operation of the plant and we therefore find them acceptable.

(10) Paragraph 4.3.3.3, transmitted originally by NRC Order dated April 20, 1981, has been modified to correct a typographical omission of a qualifying phrase.

EVALUATION TO SUPPORT LICENSE CONDITIONS

2.1.4 Integrity of Systems Outside Containment

Our letter dated July 2, 1980, indicated that the license should be amended by adding a license condition related to a Systems Integrity Measurements Program. Such a condition would require the licensee to effect an appropriate program to eliminate or prevent the release of significant amounts of radioactivity to the environment via leakage from engineered safety systems and auxiliary systems, which are located outside reactor containment. By letter dated November 13, 1980, the licensee agreed to adopt such a license condition; accordingly we have included this condition in the license.

2.1.8.c Iodine Monitoring

Our letter dated July 2, 1980, indicated that the license should be amended by adding a license condition related to iodine monitoring. Such a condition would require the licensee to effect a program which would ensure the capability to determine the airborne iodine concentration in areas requiring personnel access under accident conditions. By letter dated November 13, 1980, the licensee agreed to adopt such a license condition; accordingly, we have included this condition in the license.

IV. ENVIRONMENTAL CONSIDERATION

We have determined that the amendment does not authorize a change in effluent types or total amounts nor an increase in power level and will not result in any significant environmental impact. Haveing made this determination, we have further concluded that the amendment involves an action which is insignificant from the standpoint of environmental impact and, pursuant to 10 CFR §51.5(d)(4), that an environmental impact statement, or negative declaration and environmental impact appraisal need not be prepared in connection with the issuance of the amendment.

V. CONCLUSION

We have concluded, based on the considerations discussed above, that: (1) because this amendment does not involve a significant increase in the probability or consequences of accidents previously considered and does not involve a significant decrease in a safety margin, the amendment does not involve a significant hazards consideration, (2) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, and (3) such activities will be conducted in compliance with the Commission's regulations and the issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public.

Date: May 11, 1981

UNITED STATES NUCLEAR REGULATORY COMMISSION

DOCKET NO. 50-244

ROCHESTER GAS AND ELECTRIC CORPORATION

NOTICE OF ISSUANCE OF AMENDMENT TO PROVISIONAL OPERATING LICENSE

The U. S. Nuclear Regulatory Commission (the Commission) has issued Amendment No. 42 to Provisional Operating License No. DPR-18, to Rochester Gas and Electric Corporation (the licensee), which revised the license and its appended Technical Specifications for operation of the R. E. Ginna Plant (facility) located in Wayne County, New York. This amendment is effective as of its date of issuance.

The amendment incorporates Technical Specifications to assure operation of the plant within the limits determined acceptable following the implementation of the Three Mile Island Unit 2 Lessons Learned Category "A" items.

The application for the amendment complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations. The Commission has made appropriate findings as required by the Act and the Commission's rules and regulations in 10 CFR Chapter I, which are set forth in the license amendment. Prior public notice of this amendment was not required since the amendment does not involve a significant hazards consideration.

The Commission has determined that the issuance of this amendment will not result in any significant environmental impact and that pursuant to 10 CFR §51.5(d)(4) an environmental impact statement or negative declaration and environmental impact appraisal need not be prepared in connection with issuance of this amendment.

For further details with respect to this action, see (1) the application for amendment dated November 13, 1980, (2) Amendment No. 42 to License No. DPR-18, including the Commission's letter of transmittal and (3) the Commission's related Safety Evaluation. All of these items are available for public inspection at the Commission's Public Document Room, 1717 H Street, N. W., Washington, D. C. and at the Rochester Public Library, 115 South Avenue, Rochester, New York 14627. A copy of items (2) and (3) may be obtained upon request addressed to the U. S. Nuclear Regulatory Commission, Washington, D. C. 20555, Attention: Director, Division of Licensing.

Dated at Bethesda, Maryland, this 11th day of May, 1981.

FOR THE NUCLEAR REGULATORY COMMISSION

Dennis M. Crutchfield

Dennis M. Crutchfield, Chief
Operating Reactors Branch #5
Division of Licensing