CENTRAL FILES.

NIAGARA MOHAWK

NMP-1113

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April 24, 1979

Mr. Boyce H. Grier
Director
United States Nuclear Regulatory Commission
Region I
631 Park Avenue
King of Prussia, PA. 19406

RE: Docket No. 50-220
I.E. Bulletin 79-08

Dear Mr. Grier:

Your April 14, 1979 I.E. Bulletin 79-08 addresses concerns of events relevant to boiling water reactors identified during Three Mile Island Incident.

The attachments address those concerns.

Very truly yours,

R.R. Schneider
Vice President -
Electric Production

mtm

Attachments

xc: Director, Office of I&C (1 copy)

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CEP

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RESPONSES TO IE BULLETIN 79-08

ITEM 1.

Review the description of circumstances described in Enclosure 1 of I.E. Bulletin 79-05 and the preliminary chronology of the TMI-2 3/28/79 accident included in Enclosure 1 to IE Bulletin 79-05A.

a. This review should be directed toward understanding: (1) the extreme seriousness and consequences of the simultaneous blocking of both trains of a safety system at the Three Mile Island Unit 2 plant and other actions taken during the early phases of the accident; (2) the apparent operational errors which led to the eventual core damage; and (3) the necessity to systematically analyze plant conditions and parameters and take appropriate corrective action.

RESPONSE TO 1.a.

a. Throughout the incident at Three Mile Island, Nine Mile Point employees followed the chronology of events as released by the Atomic Industrial Forum. These releases were posted on bulletin boards throughout the station. In addition, IE Bulletin 79-08, 79-05, and 79-05A have been routed to all licensed and non-licensed operators and licensed staff members for their review. At the completion of the current outage, operators and licensed staff members will receive a formal review of the events included in IE Bulletins 79-05 and 79-05A as part of the Operator Requalification Program.

b. Operational personnel should be instructed to (1) not override automatic action of engineered safety features unless continued operation of engineered safety features will result in unsafe plant conditions (See Section 5a of this bulletin); and (2) not make operational decisions based solely on a single plant parameter indication when one or more confirmatory indications are available.

RESPONSE TO 1.b.

b. Operational orders (Night Orders) issued on April 20, 1979, instructed all operations department personnel:

1) Not to override automatic action of engineered safety features unless continued operation of engineered safety features will result in unsafe plant conditions.
2) Not to make operational decisions based solely on a single plant parameter indication when one or more confirmatory indications are available.

In addition, these points will be re-stressed in the formal review conducted as part of the Operator Requalification Program mentioned above.

ITEM 1 (continued)

c. All licensed operators and plant management and supervisors with operational responsibilities shall participate in this review and such participation shall be documented in plant records.

RESPONSE TO 1.c

c. *Upon completion of a and b above, documentation will be entered in the individual training files.*

ITEM 2.

Review the containment isolation initiation design and procedures, and prepare and implement all changes necessary to initiate containment isolation, whether manual or automatic, of all lines whose isolation does not degrade needed safety features or cooling capability, upon automatic initiation of safety injection.

RESPONSE TO ITEM 2

A review of the design of containment and primary coolant isolation initiation has been completed and no changes are considered to be necessary. Features of the design are; Automatic safety injection (core spray initiation) would occur on either 1) high drywell pressure or 2) low-low reactor vessel water level. These signals also initiate the following:

A) Containment isolation - 1 or 2
B) Primary coolant isolation - 2
(main steam, cleanup, shutdown cooling)

Primary coolant isolation is not initiated on high drywell pressure because these are closed systems capable of handling radioactivity levels associated with normal operation. Abnormally high levels of radioactivity could result from fuel damage caused by reactor water level dropping below the top of the fuel. This low water level which may result in fuel failures would cause primary coolant system and primary containment isolation.

Procedure review has been completed; present procedures are considered to be satisfactory.

ITEM 3.

Describe the actions, both automatic and manual, necessary for proper functioning of the auxiliary heat removal systems (e.g., RCIC) that are used when the main feedwater system is not operable. For any manual action necessary, describe in summary form the procedure, by which this action is taken in a timely sense.

RESPONSE TO ITEM 3

The auxiliary heat removal system that would be utilized at Nine Mile Point Unit #1 if the main feed water system is not operable is the Emergency Condenser System. This system has double capacity for times greater than 100 seconds after a scram. Either half of the emergency cooling system may be independently initiated and isolated. The system is automatically initiated on either high reactor pressure 1080 psig or low-low reactor water level signals 5" indicator scale (10 second time delay); upon automatic initiation, the condensate return valves to the reactor (DC solenoid operated air valves) open allowing a return path to the reactor.

The system can be manually initiated at any time by opening the condensate return valve from the control room. Cool down and pressure control is available by cycling either the condensate return isolation valve or the steam supply isolation valves.

ITEM 4.

Describe all uses and types of vessel level indication for both automatic and manual initiation of safety systems. Describe other redundant instrumentation which the operator might have to give the same information regarding plant status. Instruct operators to utilize other available information to initiate safety systems.

RESPONSE TO ITEM 4

The attached is a description of the uses and types of vessel level indication for both manual and automatic initiation of safety systems. Included is a description of redundant instrumentation which the operator has available to aid in determining plant status.

VESSEL INSTRUMENTATION

I. VESSEL LEVEL INSTRUMENTATION

A. GEMAC Instrumentation

1. General Description

   a. Uses high pressure leg and low pressure leg
   b. High pressure leg is reference leg. Connected to unlagged condensing pot. Maintains constant water level in leg.
   c. Low pressure leg is variable leg, connected to source of water level being monitored.
   d. Level detector monitors the differential pressure between the two legs and converts ΔP to usable electronic signal.
   e. Compensated for density by reactor pressure signal.
   f. Indicates on meters or charts and also used by feedwater control.

2. Three ranges of GEMAC Instrumentation

   a. Narrow range GEMAC Figure 1

      1. Two systems; channel 11 and channel 12
      2. Instrument zero is 302'9"
      3. Range of N.R. GEMAC's +3' to -5'
      4. Normal level control band is 0.0' to 1.0' (302'9" to 303'9")
      5. N.R. GEMAC's located:
         a) Vertical section "F" panel, 2 meters
         b) Cleanup section "K" panel through selector switch
         c) Console section "E" panel through selector switch
      6. "F" panel vertical section has chart recorder. Signal through selector switch on console.
      7. N.R. GEMAC used by feedwater control system
      8. Level alarms actuated by switches on chart recorder
         a) High level → +2' (304'9")
         b) Low level → -6" (302'3")

   b. Wide Range GEMAC

      1. Uses same variable leg tap as N.R. GEMAC. Condensing pot taps off top of vessel, giving different reference leg than N.R. instrumentation.
      2. W.R. GEMAC has meter on the vertical section of "F" panel by the two N.R. meters
      3. Range of W.R. GEMAC is 23' to -7' (325'9" to 295'9")
      4. Instrument zero is 302'9".

c. Flange level GEMAC

1. Instrument zero is 315'9", corresponds to 13' (315'9") on W.R. GEMAC.
2. Uses same detector as W.R. GEMAC.
3. Meter indication has suppressed range so it will only indicate =3' to -3' (318'9" to 312'9").

B. Rosemount Level Instrumentation

1. General Description

a. Rosemount level instrumentation utilizes existing Yarway temperature compensated self-venting reference column. A high and low pressure leg from the column are connected to a differential pressure transmitter. The low pressure leg is the variable tap of the column. (See Figure 3)
b. In the reference column, both the reference and variable legs are kept at the same temperature. The variable leg has a standpipe that extends into the condensing pot. (Figure 3) The overflow of excess water will continuously replace the colder water with hot water which causes the colder water to flow back to the vessel. This flow keeps the variable leg temperature high. Using metal clamps to aid in heat transfer plus the fact that the two legs are in close proximity, cause the reference leg to be maintained at some higher temperature.
c. Figure 4 shows a cold reservoir which is a surge volume for the Rosemount column. The "auxiliary head chamber assembly" makes up for level surges in the condensing chamber. On a level increase, the excess water will surge into the cold reservoir; on a level decrease, the cold reservoir will supply cooler water to the condensing chamber as well as keeping some level in the condensing chamber.
d. The Rosemount level detector has a capacitor diaphragm network to separate the high and low pressure legs. As the level changes in the variable leg, the pressure on the diaphragm also changes. This change in pressure will cause the capacitance of the diaphragm to change. The changing capacitance is electronically sensed and amplified by the transmitter which feeds the trip unit level indicators. Small pressure differences in the reference to variable leg indicate high levels, large differences indicate low levels.

2. Hi/Lo and Low-Low Level

a. Two channels of Rosemount level indication - ch 11 and ch 12.
b. There are two level transmitter/trip units in each channel that give protective actions when level setpoints are exceeded.
c. Each channel has a remote read-out in the Control Room, on the vertical section of the "F" panel.

d. Local Rosemount level indicators (A,B,C,D), one per cabinet which are located in each corner of the Reactor Building on Elevation 281.

e. The range of the Rosemount instrument is 0" to 100".

f. Instrument zero is 297'4".

g. The normal control band is 65" to 83".

1) 95" - Turbine trip and stop valve closure 36-03 A,B,C,D (Hi Level)

2) 53" - Reactor scram and after 5 seconds time delay, Turbine trip. (Low Level) 36-03 A,B,C,D

3) 5" - Reactor Vessel Isolation - includes 36-04 A,B,C,D (Low-Low Level)
- MSIV Closure
- Cleanup System Isolation
- Shutdown Cooling Isolation
- Emergency Cooling Vent and Drain Isolation

5" - Containment Isolation - includes:
- N_2 inerting valves (12)
- Drywell equipment drain line valves (2)
- Floor drain valves (2)
- Oxygen sampling line valves (8)
- Core Spray test discharge valves (2)
- Drywell CAM isolates
- TIP automatically retracts and block valve closes

5" - Recirculation Pumps trip

5" - With decreasing reactor pressure signal of <365 psi Core Spray System will initiate

5" - With a time delay of 10 seconds, Emergency Cooling will initiate.

5" - With a high drywell pressure signal, plus a time delay, containment spray will initiate.

3. Low-Low-Low Level 36-05 A, B, C, D

a. Two channels of Rosemount level indication ch 11 and 12

b. There are two level transmitters in each channel that give protective actions when level set points are exceeded.

c. Variable leg tap off core spray sparger; reference leg is N.R. GEMAC condensing pot.

d. Spargers located inside shroud.

e. Indicating is -124.1 to -265.4"; local indication - 1 in each of the 4 new cabinets.

f. Level transmitter trip units have inputs to RPS for automatic depressurization of reactor vessel. (ADS also needs high drywell pressure signal plus a time delay to function.

g. Low-Low-Low level setpoint is -127.1" meter scale.

1) Elevation 294'10" (7'11" below GEMAC instrument zero).

2) 4'8" above top of active fuel (TAF 290'2".

C. Yarway Level Instrumentation

1. Two Yarway Level indicators are provided, one in each of the East and West Instrument Rooms in the Reactor Building Elevation 281'. These are connected to the same reference described in B.1a through 1c.
2. These instruments provide redundant local Rx Vessel Level indication and would be operable in the event of total loss of electrical power.
3. The Yarway level detector has a diaphragm that keeps the high pressure and low pressure legs apart. As the pressure changes, due to level change, the diaphragm will move. The movement of the diaphragm causes a magnet to move, a pointer will follow the movement of the magnet to indicate the level. Smaller differential pressure readings mean the actual level is approaching the level in the reference leg so there will be a high level indicated. Large differential pressure will give low level indications.

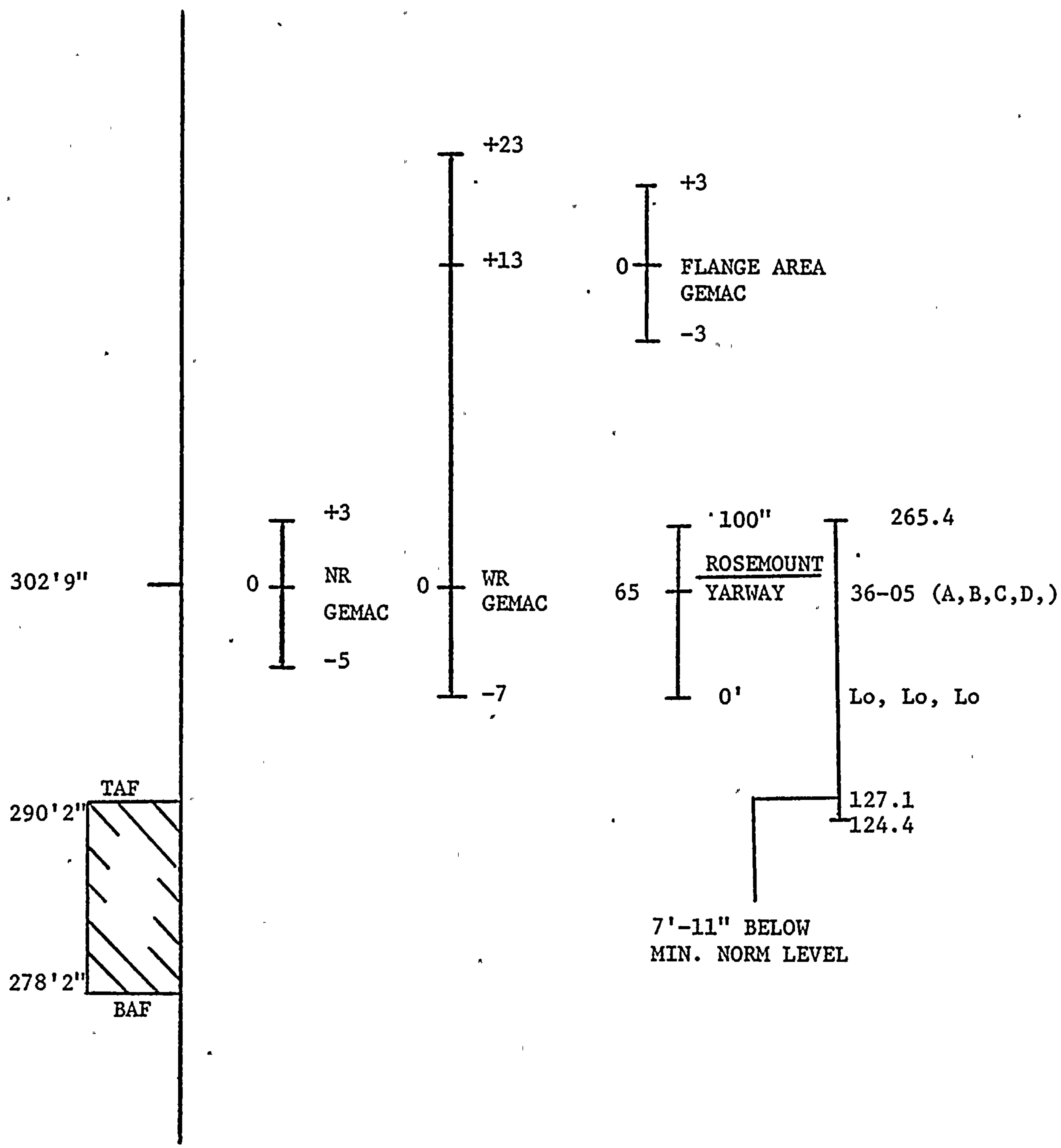

FIG. 1 - REACTOR VESSEL LEVEL INSTRUMENTATION COMPARISON

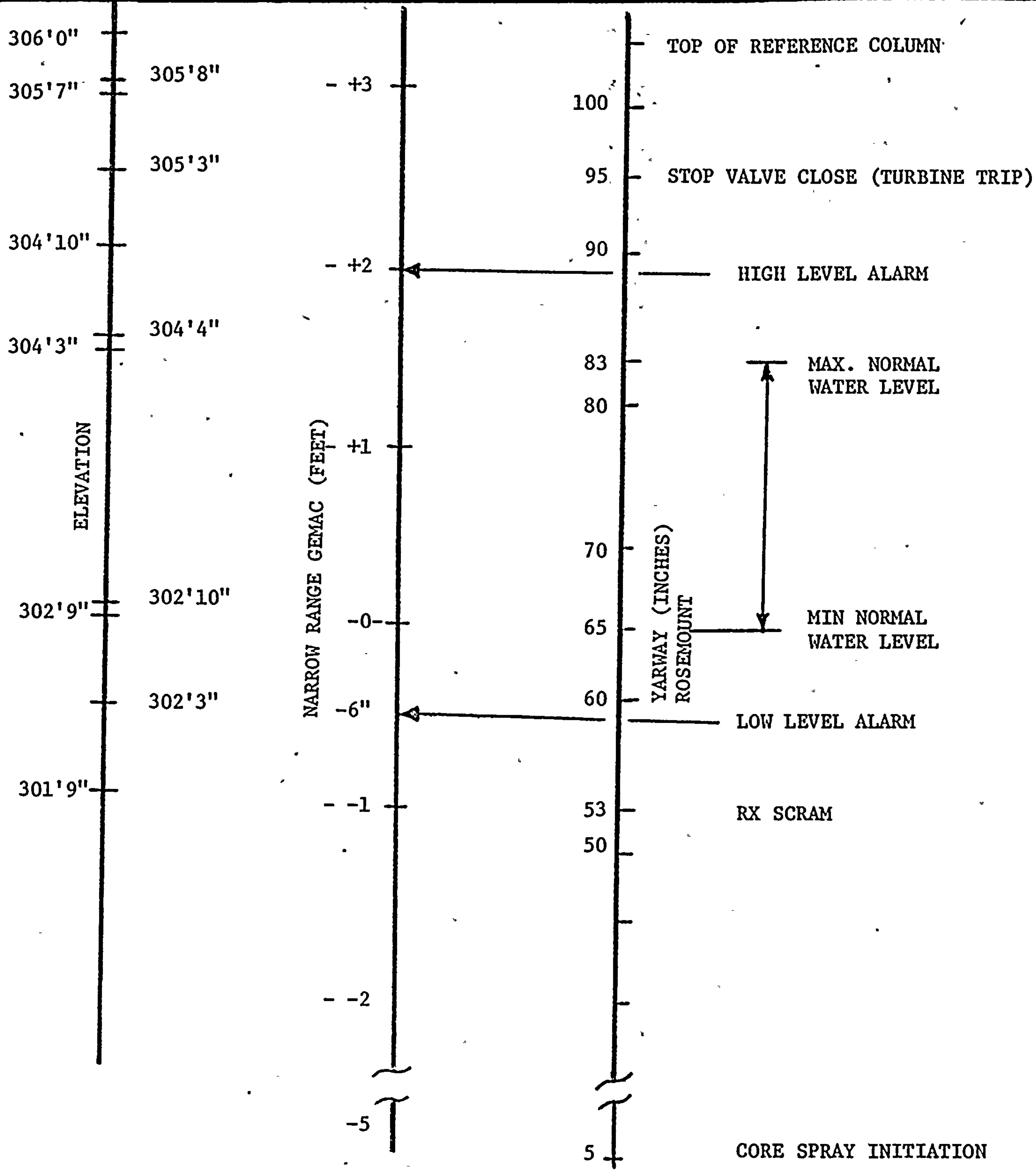
306'0"
305'8"
305'7"
305'3"
304'10"
304'4"
304'3"
ELEVATION
302'10"
302'9"
302'3"
301'9"
+3
+2
+1
-0-
-6"
-1
-2
-5
NARROW RANGE GEMAC (FEET)
TOP OF REFERENCE COLUMN
100
95
STOP VALVE CLOSE (TURBINE TRIP)
90
HIGH LEVEL ALARM
83
MAX. NORMAL WATER LEVEL
80
70
65
MIN NORMAL WATER LEVEL
60
YARWAY (INCHES) ROSEMOUNT
LOW LEVEL ALARM
53
RX SCRAM
50
5
CORE SPRAY INITIATION

FIGURE 2

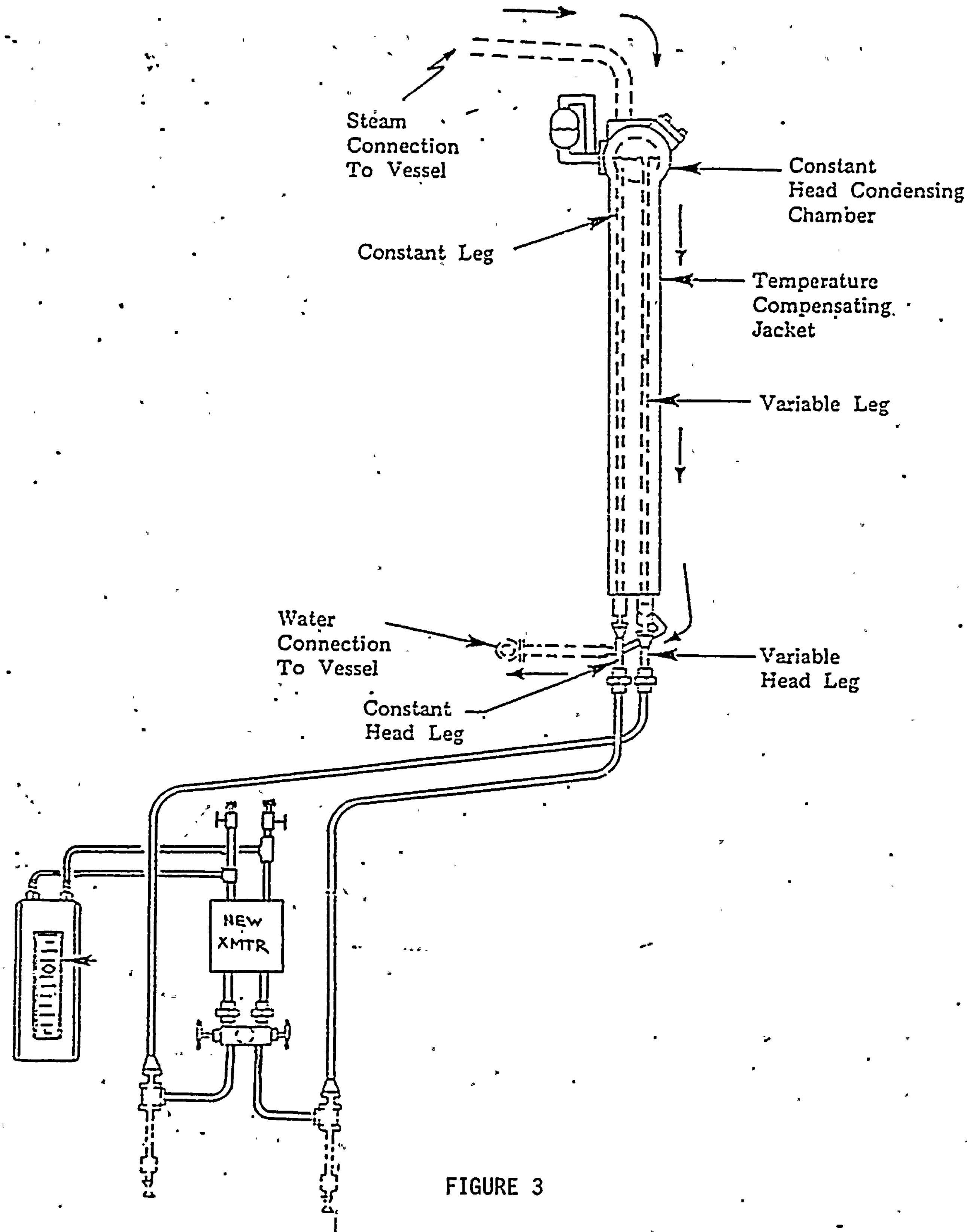

FIGURE 3

ROSEMOUNT/YARWAY LIQUID LEVEL INDICATOR WITH
TEMPERATURE COMPENSATED REFERENCE COLUMN

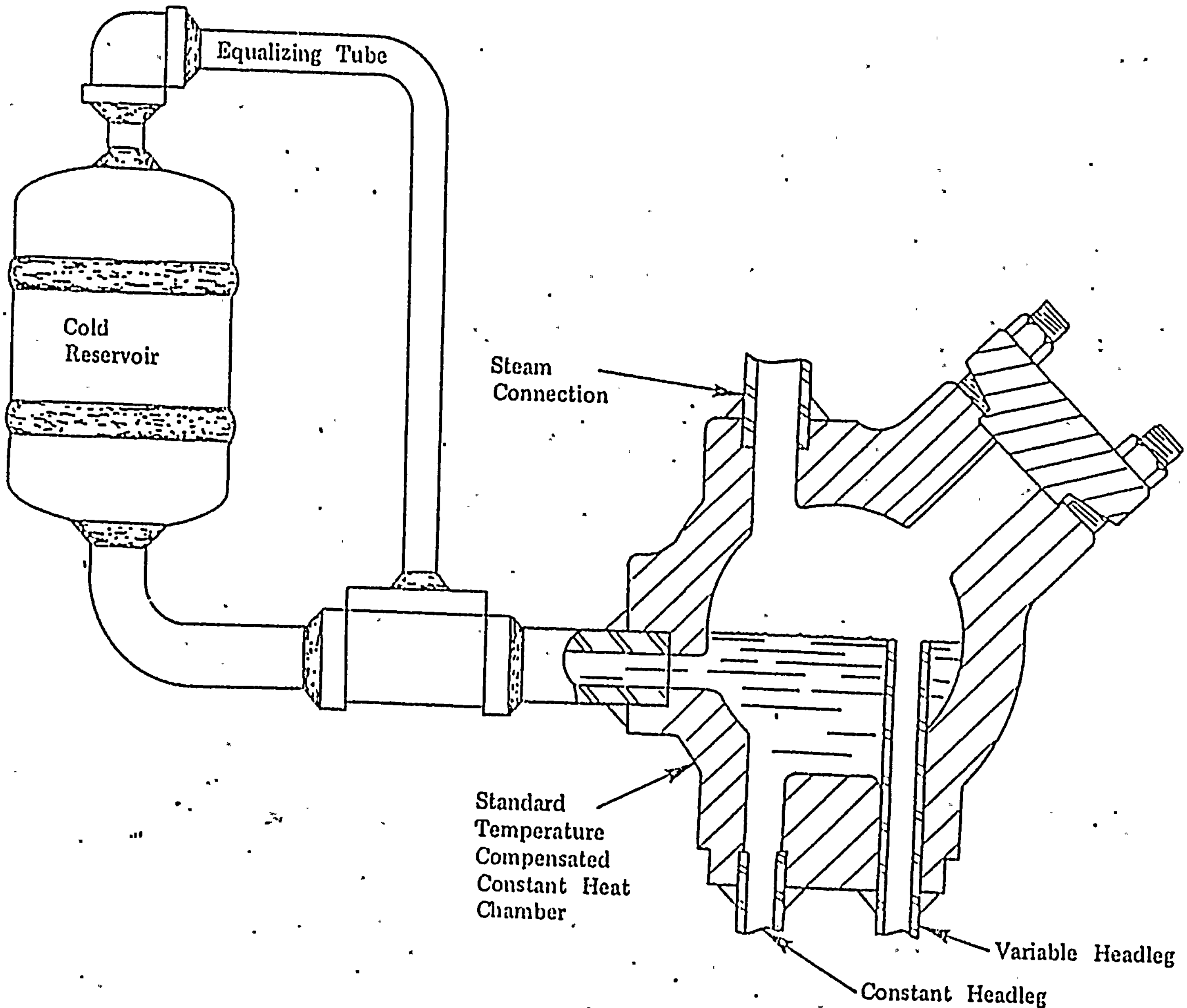

Figure 4

ROSEMOUNT LEVEL INDICATOR AUXILIARY HEAD CHAMBER ASSEMBLY

ITEM 5.

Review the action directed by the operating procedures and training instructions to ensure that:

a. Operators do not override automatic actions of engineered safety features, unless continued operation of engineered safety features will result in unsafe plant conditions (e.g. vessel integrity).

RESPONSE TO 5.a

a. *Site Administrative Procedure APN-2A, "Conduct of Operations and Composition and Responsibilities of Station Organization", delineates the responsibilities and actions of on-shift operators. This procedure has, since its inception in 1969, stressed conservative use of instrumentation; ..." he has the responsibility to believe and respond conservatively to instrument indications unless they maybe otherwise proven to be incorrect. He shall at all times operate in accordance with approved procedures unless immediate and unforeseen action is required to ensure the safety of the reactor, the plant, plant personnel or the general public".*

This section will be expanded to include clarifications on overriding automatic engineering safety features and re-emphasis on use of redundant parameter indications. In addition, these points will be stressed in the Operator Requalification Program lectures (See Response 1.b).

b. Operators are provided additional information and instructions to not rely upon vessel level indication alone for manual actions, but to also examine other plant parameter indications in evaluating plant conditions.

RESPONSE TO 5.b

b. *All station operating and special procedures have been reviewed for these areas of concern; amplification and clarification will be made to specific procedures identified in this review. Any changes to these procedures will be included as information and instructions in the Operator Requalification Program.*

The review process of this item is complete, changes to procedures will be completed prior to return to power from current refueling outage.

ITEM 6.

Review all safety-related valve positions, positioning requirements and positive controls to assure that valves remain positioned (open or closed) in a manner to ensure the proper operation of engineered safety features. Also review related procedures, such as those for maintenance, testing, plant and system startup, and supervisory periodic (e.g., daily/shift checks,) surveillance to ensure that such valves are returned to their correct positions following necessary manipulations and are maintained in their proper positions during all operational modes.

RESPONSE TO ITEM 6

All safety related system procedures contain valve line ups for required position of valves. According to Niagara Mohawk Power Corporation practices, job specifications, and procedures, only qualified operations personnel may position valves under the direction of the shift control operator (licensed reactor operator) or the Station Shift Supervisor (senior reactor operator). Valve positions may be altered for maintenance or testing but only in conformance with APN-7, "Procedure for the Control of Equipment Mark-ups", and APN-13, "Procedure for Control of Station Corrective Repair or Maintenance", and utilizing a company wide procedure for mark-up. Under Paragraph 5.6.8 of APN-13, ..."the person completing the maintenance or his supervisor shall indicate on the work request form whether or not an operability test is required by Technical Specifications or the Maintenance Procedure".

Safety Related Maintenance procedures contain requirements for post operability test performance to demonstrate operable status in conformance with Technical Specifications. Additionally, if Technical Specification requirements can not be met because of a system or component failure, the Station Shift Supervisor shall take the corrective actions in accordance with APN-8, "Test and Inspection Program" ... "he shall immediately initiate test or operations provided by Technical Specifications which may demonstrate that the station continues to meet the limiting condition for operation". The Station Surveillance Program contains inoperable component tests and periodic frequency tests to meet these objectives.

A review of these tests has been accomplished and each has a "return to normal" section to ensure proper system line up following any necessary manipulations. The action required by this item is complete.

ITEM 7.

Review your operating modes and procedures for all systems designed to transfer potentially radioactive gases and liquids out of the primary containment to assure that undesired pumping, venting or other release of radioactive liquids and gases will not occur inadvertently.

In particular, ensure that such an occurrence would not be caused by the resetting of engineered safety features instrumentation. List all such systems and indicate:

a. Whether interlocks exist to prevent transfer when high radiation indication exists, and

b. Whether such systems are isolated by the containment isolation signal.

c. The basis on which continued operability of the above features is assured.

RESPONSE TO ITEM 7

There are three potential pathways for radioactive gases or liquids to be transferred out of the primary containment:

a. N_2 vent and purge system
b. CAD System
c. Drywell floor and equipment drains

All of the above systems would isolate on a containment isolation signal. Overrides are provided for A and B such that they can be manually re-opened for controlled venting and monitoring purposes. Venting would take place through the reactor building emergency ventilation system. This system would not isolate on high radiation. By procedure, venting is allowed only after containment atmosphere has been sampled and analyzed.

The drywell floor and equipment drains transfer liquid under normal operation. These lines isolate on high drywell pressure and low-low level. Since level below top of fuel is required to produce significant fuel failures, high radioactive liquid would not be automatically transferred to the waste building. Activity in these lines is not normally monitored, however, positive valve position indication is provided in the control room.

The drywell high pressure signal which initiates containment isolation has a seal-in-feature so that both RPS channels must be cleared and manual resetting accomplished before any isolation valves not provided with overrides can be re-opened. Thus, for the pumping of drywell drains to occur, two overt actions would be required. Procedures are being modified to ensure that these positive controlls remain in effect during events which produce significant radioactive liquids in the containment. Procedure changes will be completed prior to return to power from current refueling outage.

ITEM 8.

Review and modify as necessary your maintenance and test procedures to ensure that they require:

a. Verification, by test or inspection, of the operability of redundant safety-related systems prior to the removal of any safety-related system from service.

b. Verification of the operability of all safety-related systems when they are returned to service following maintenance or testing.

RESPONSE TO ITEM 8.a and 8.b

Station Safety-related Operating Procedures require that the operability of redundant safety systems be proven prior to the removal of any safety-related system from service, as well as when returned to service after maintenance. These tests are performed using Inoperable Component Surveillance Tests as specified in the Technical Specifications.

c. Explicit notification of involved reactor operational personnel whenever a safety-related system is removed from and returned to service.

RESPONSE TO ITEM 8.c

c. *Station Administrative Procedure APN-8, Paragraph 6.2.2, requires that the Station Shift Supervisor be immediately notified if a system or component can not meet the Technical Specification requirements. Also, as outlined in Item #6 above, APN-7 and APN-13 requires notification and concurrence of the Station Shift Supervisor for removal of and return to service of safety-related systems.*

Review of this item is complete and procedures do satisfy indicated requirements.

ITEM 9.

Review your prompt reporting procedures for NRC notification to assure that NRC is notified within one hour of the time the reactor is not in a controlled or expected condition of operation. Further, at that time, an open continuous communication channel shall be established and maintained with NRC.

RESPONSE TO ITEM 9

APN-21, "Procedure for Reporting Variations from Normal Plant Operations, Defects and Noncompliance", has been modified to include the one-hour notification and communication channel required by this item.

ITEM 10.

Review operating modes and procedures to deal with significant amounts of hydrogen gas thay may be generated during a transient or other accident that would either remain inside the primary system or be released to the containment.

RESPONSE TO ITEM 10

Should hydrogen be generated by either radiolysis or metal water reaction, the following methods are available to relieve this from the reactor vessel:

a. The reactor head vent, located on top of the reactor vessel, relieves to the drywell equipment drain tank by remote manual control from the control room. If low water level has occurred, which may result in fuel damage, the drain tank would be isolated and overflow would be to the drywell atmosphere.

b. The relief valves, located on the main steam lines, relieve to the torus. At Nine Mile Point #1 there is a significant distance between the top of the core and the main steam line (approximately 20 feet). This allows significant amounts of noncondensibles to be accomodated.

c. Loss of coolant accident or safety valve actuation - direct release path to the primary containment.

Once the hydrogen has been vented from the reactor vessel, its concentration in the primary containment can be monitored and diluted with nitrogen from the CAD system. However, venting of the primary containment would be necessary should repressurization by CAD to 20 psig occur. Vent initiation would not be required for approximatley 38 days after a LOCA.

Procedure changes for venting significant amounts of hydrogen gas are being modified and will be completed prior to return to power from current refueling outage.