ILLINOIS POWER COMPANY

U-0357
L30-81 (12-01)-6
500 SOUTH 27TH STREET, DECATUR, ILLINOIS 62525

December 1, 1981

Mr. James R. Miller, Chief
Standardization & Special Projects Branch
Division of Licensing
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Dear Mr. Miller:

Clinton Power Station Unit 1
Docket No. 50-461

The attached material represents responses which were discussed with Messrs Ernie Rossi and Rick Kendall during a meeting on November 30, 1981. These responses were found to be acceptable as stated and resolve the issues. The following items are either closed or confirmatory depending on the action required:

Response Time Testing

Vessel Level Measurement Errors

Vessel Level Sensing Lines Common to Control and Protection Systems

Containment Atmosphere Monitoring System

Sincerely,

G.E. Huller for J.D. Geier

J.D. Geier
Manager, Nuclear Station Engineering

Attachments

cc: J.H. Williams, NRC Clinton Project Manager
H.H. Livermore, NRC Resident Inspector
R. Kendall, NRC ICSB

Add: Ernie Rossi
Rick Kendall

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S.1/1

Issue Title:

Response Time Testing of NSPS Solid State Logic.

Issue:

IPC currently believes that response time testing of the solid state digital NSPS (Nuclear System Protection System) logic at Clinton is unnecessary. The staff's position is that response time testing of the entire protection system is necessary and we are currently discussing this issue with IPC.

Response:

IPC will submit the Technical Specification information which will address the area of response time testing for the reactor protection system, the isolation system, and the emergency core cooling systems as part of the Tech. Spec. submittal. The Technical Specification information will provide the portion of the system to be tested, the frequency of the testing, and the required response times.

Response time testing of the solid state logic of the NSPS system will be included in the overall response time testing from the initiating parameter to the actuated device. The Technical Specifications dealing with the reactor protection system, the isolation system and the emergency core cooling systems will provide information on the RPS Channel to be tested, the frequency of testing and the required response times.

Action Required

Submit Tech. Spec. Appendix.

Issue Title: Vessel Water Level Measurement Errors

Issue:

Applicant is asked to evaluate the effects of high temperatures in reference legs of water level measuring instruments subsequent to high energy line breaks. A preliminary evaluation has been completed and indicates that if, following a small break LOCA, drywell temperatures are allowed to remain above saturation too long, reference leg boil off could cause errors in vessel level instrumentation.

Response:

Review of Reactor Water Level Measurement Instrumentation:

Reactor vessel water level is measured by means of differential pressure between a reference leg and a variable leg. The reference leg is connected to the upper part of the vessel (steam zone) and provides a constant leg reference using an overflow type condensing chamber. The variable leg is connected to the lower part of the vessel. The differential pressure is proportional to the water level.

The cold reference leg reactor water level measurement design for Clinton Power Station (CPS) is illustrated in Figure 1. Reactor vessel water level is measured by differential pressure transmitters which measure the difference in static head between two columns of water. One column is a "cold" (ambient temperature) reference leg outside the reactor vessel, the other is the reactor water inside the reactor vessel. The measured differential pressure is a function of reactor water level.

The cold reference leg is filled and maintained full of condensate by a condensing chamber at its top which continuously condences reactor steam and drains excess condensate back to the reactor vessel through the upper level tap connection to the condensing chamber. The upper vessel level tap connection is located in the steam zone above the normal water level inside the vessel. Thus, the reference leg presents a constant reference static head of water to the high pressure tap on the d/p transmitter. The low-pressure tap of the transmitter is piped to a lower-level tap on the reactor vessel which is located in the water zone below the normal water level in the vessel. The low-pressure side of the transmitter thus senses the static head of water/steam inside the vessel above the lower vessel level tap. This head varies as a function of reactor water level above the tap and is the "variable leg" in the differential pressure measured by the transmitter. Lower taps for various instruments are located at various levels in the vessel water zone to accommodate both narrow- and wide-range level measurements (see Figure 2).

Problem Description

High drywell temperature can introduce errors in the indicated vessel water level in two ways:

1. by causing the density changes in the water in the sensing lines due to increased temperature in the drywell.

2. by boil-off of the reference leg when the reactor is depressurized below the saturation pressure of the reference leg temperature (drywell temperature).

Errors due to density change are eliminated by making the vertical drops of the sensing lines for the reference and variable legs the same. The vertical drop of the sensing lines in the CPS design are equal within approximately one foot. This results in negliable error due to change in density.

The amount of error due to boil-off is a function of the amount of vertical drop of the reference leg inside the drywell. The following is an analysis of the reference leg boiling problem as applicable to the CPS design.

Reference Leg Flashing/Boil-Off

Small (e.g., .01 ft^2) and intermediate (e.g., .04 ft^2) break accidents (LOCA's) that discharge steam into the drywell (at temperatures as high as 330°F) for an extended time period could result in substantial heat-up of components/air in the drywell (including reactor water level sensing lines). If the reactor is subsequently depressurized below 103 psia, water in the reactor water level sensing lines located in the drywell will flash.

General Electric has conservatively evaluated many steam break accidents and has determined that, for the worst case scenario (small break accident with ADS operation after 1800 seconds), flashing will result in a loss of up to 20% of the water in the sensing lines. Water in the variable leg sensing line will be replenished by drain back from the reactor, while water in the reference leg sensing line will continue to be gradually depleted due to boil-off. Loss of water from the reference leg results in a sensed reactor water level that is higher than the actual reactor water level.

<u>Operator Actions and Conditions that Prevent and/or Eliminate Flashing/Boil-Off</u>:

Flashing/Boil-Off will not occur if:

a. The break discharges two-phase fluid only. Breaks that result in liquid/two-phase discharge do not result in reference leg flashing/boil-off because the discharge flashes to a temperature less than that of the reactor;

b. The drywell achieves the higher temperatures before level is recovered such that the saturated liquid spilling out of the break and cooling the steam lines and drywell environment terminates the heatup transient;

c. The reactor pressure is maintained above 103 psia.

In addition, even if flashing/boil-off were to occur, it would not be a concern if the operator follows the emergency procedure guidelines (EPG) and maintains reactor level in the normal water level range. Furthermore, the error due to flashing/boil-off will be eliminated if:

a. The operator follows the EPG and takes action to refill the reference leg after reactor depressurization if the temperature near the reference leg has exceeded the reactor saturation temperature and continues reactor injection until the temperature near the reference leg is below 212°F; or

b. The operator determines that a flashing/boil-off condition exists and takes corrective action to refill the reference leg. Indications available to the operator that indicate the reference leg flashing/boil-off are:

   1. erratic level indication

   2. mismatch between narrow, wide and upset range level indicators and recorders. (Note: Since EPG requires the operator to monitor water level from multiple indications, he should be aware of level instrument mismatch and hence flashing/boil-off conditions.)

The emergency procedure guidelines address RPV water level and reference leg boiling in a number of ways. Cautions No. 6 and No. 7 point out to the operator that high drywell temperature near the reference legs can result in unreliable indicated level. The Level Control Guideline is entered when the RPV water level is below the low level scram setpoint. The operator is directed to restore and maintain RPV water level to any of the injection systems. If water level can not be maintained or can not be determined, the operator is directed to enter the Contingency Number 1 procedure.

Contingency #1 deals with level restoration and directs the operator to enter Contingency #2 or #3 if the RPV water level can not be determined. Contingency #2 covers rapid depressurization of the RPV by use of ADS valves or other SRV if ADS valves can not be opened. Here again, the operator is given further direction if the RPV water level can not be determined. He is to enter the Contingency #6 procedure. He is also advised to enter Contingency #6 if the temperature near the cold reference leg instrument sense line reaches the RPV saturation limit. Contingency #2 is concerned with core cooling without injection.

In Contingency #6, the operator is provided direction in flooding the RPV. The situation where level can not be determined is covered by directing the operator to fill all RPV level instrumentation reference columns by flooding the vessel and continuing to inject water until temperature near the cold reference leg is below 212°F and RPV water level instrumentation is available.

<u>Worst Case Analysis</u>:

The worst case situation arises when the drywell is allowed to heat up as the result of a steam leak. All automatic ECCS actuations would have initiated very early in the event to maintain reactor level. Under such circumstances, depressurization by means of the automatic depressurization system (ADS) would not occur unless a low pressure core spray pump (500 psig head) were already operating nor would any errors exist in level measurement due to boil-off because the reactor would not yet be depressurized below 103 psia.

With these pumps running, as soon as the reactor pressure is reduced to below the pump head, the vessel would flood up; this would be at a point in excess of the pressure at which errors from boil-off could occur. If the pressure is reduced below 103 psia, the water in the sensing legs would partially boil-off but would quickly backfill due to flooding up the vessel eliminating any errors due to boil-off.

In the case where the initial stages of the event are long passed (automatic ECCS operation complete) and the operator has taken over manual control, the emergency procedures govern the actions taken. The emergency procedures direct depressurization by manual actuation of the ADS, in which case, interlocks prevent actuation unless at least one of the above described pumps is running, the result would be the same as in the case described above. Where the operator fails to follow the direction to use ADS and instead uses other safety relief valves (SRVs), the emergency procedures are the same; he is directed to start the low head pumps prior to depressurization. In each of these situations, mitigating action is already being taken by pumping in water to flood up the vessel prior to the point where errors would appear.

Since the maintenance of the reactor level is the primary concern of the operator under the postulated conditions, it is difficult to perceive that depressurization could occur without pumps being on to flood the vessel. In the unlikely event the operators should make such gross procedural errors as to use the SRVs instead of ADS and to neglect the starting of any pumps prior to depressurization to 103 psia, the reference leg initial boil-off would be about 20%. Analysis shows it would take about 9½ hours to boil-off the remaining water in the reference leg if no operator action is taken.

The operator is instructed by the emergency procedure guidelines to monitor the drywell temperature and when, that temperature reaches the RPV saturation limit as determined from the figure given in the emergency procedures, to depressurize and flood up the vessel to refill the reference lines. In order to alert the operator to the condition of high drywell temperature in the area of the reference legs, temperature sensors with control room output will be added to the CPS design. These sensors will be in addition to those already included in the CPS design. As directed by the emergency procedures, the operator must monitor the temperature in the area of the reference legs and determine if the reference leg is reaching the RPV saturation limit. Following the emergency procedures the operator will flood the vessel and refill the reference if there is an indication of lose of water from the reference leg.

Conclusion

Based on our evaluation of the automatic operation of systems and manual actions to be taken under emergency procedures during the event postulated, we find that it is highly unlikely that any action will be taken based on erroneous level information and that adequate emergency procedures are provided which specifically identifying this unique situation and which spell out the measures to be taken to rectify erroneous level readings. It is our conclusion that the design of the reactor vessel level measuring system is acceptable and sufficient provision has been made for potential errors due to boil-off of the reference leg under small steam break conditions.

Action Required

The CPS FSAR will be revised to include a description of the temperature monitoring associated with the reference leg.

References:

1. GE document, NEDO-24708A, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactor, Volumns 1 and 2," August, 1979.

2. GE document, NEDO-25224, "GESSAR Assessment Report - Review of BWR/6 Protection in Depth Against Transient and Accident Events," December, 1979.

3. GE document, NEDE-24801, "Review of BWR Reactor Vessel Level Measurement," April, 1980.

Table 1

SUMMARY OF SIGNIFICANT REACTOR VESSEL LEVELS

Level	Action	Approximate Elevation Above TAF (ft)
Level 8	Main Turbine Stop Valve Closure, HPCI/HPCS Injection Terminated, Trip RCIC Turbine, Trip Reactor Feedwater Pumps and Condensate Booster Pumps, Scram (run mode only)	18
Level 7	Alarm	17
	Normal Operating Reactor Level is Maintained Below the High Level Alarm and Above Low Level Alarm.	
Level 4	Alarm, Run Back Recirculation Flow on Loss of One Feed Pump.	16-¼
Level 3	Scram and Run Back Recirculation Flow, Permissive for ADS, Close RHR Shutdown Isolation Valves.	14-½
Level 2	Initiate Reactor Core Isolation Cooling System, Division 3 Diesel Generator and High Pressure Core Spray System, Close Isolation Valves, Except RHR Shutdown Isolation Valves and MSIV's, Shutdown Recirculation System.	11
Level 1	Initiate Residual Heat Removal Pumps and LPCS, Start Division 1 and 2 Diesel Generators, Close MISV's and Initiate ADS (in conjunction with other signals.)	1-½
Top of Active Fuel		0
Bottom of Active Fuel	Fuel Zone Indication	-12-½

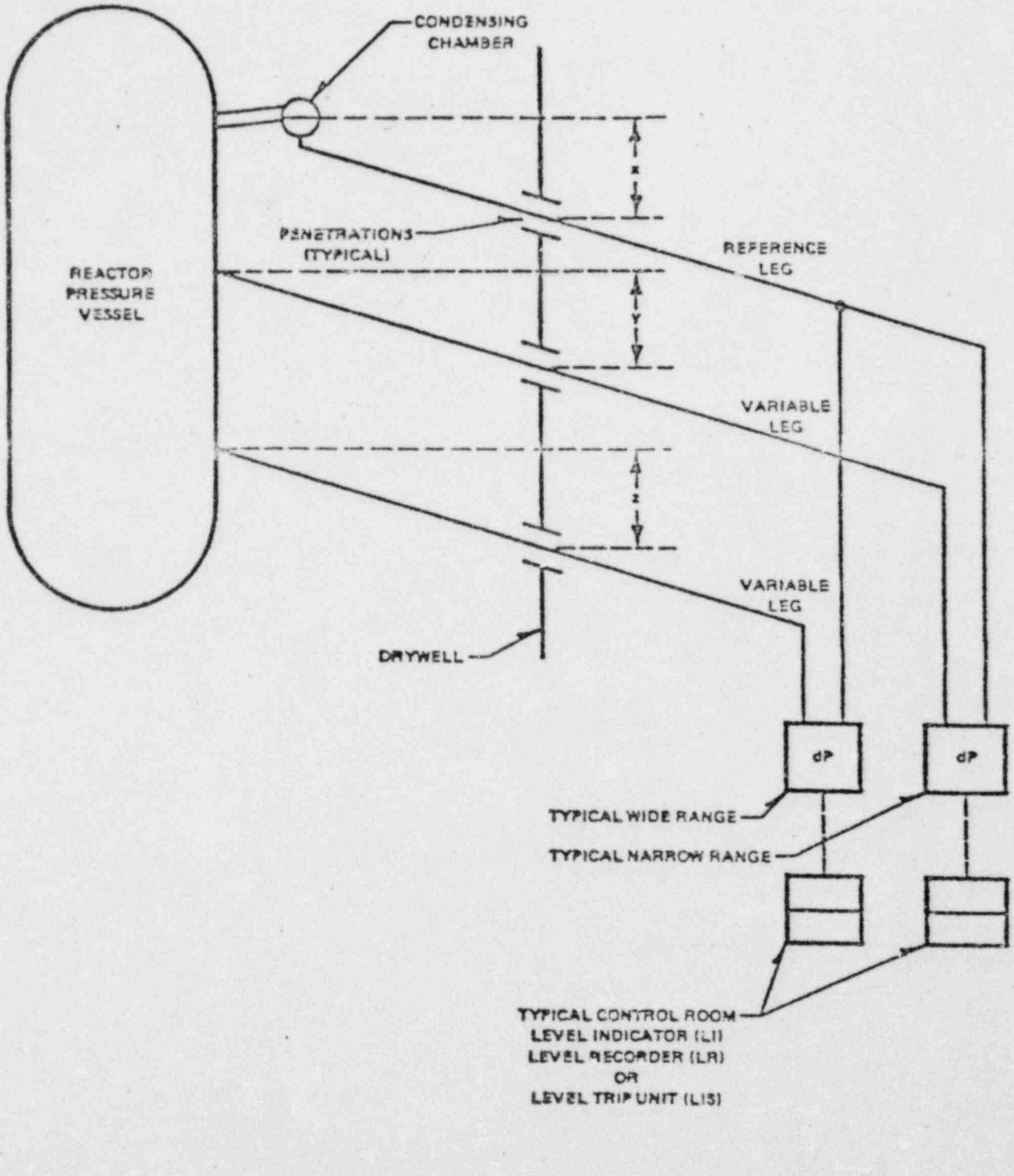
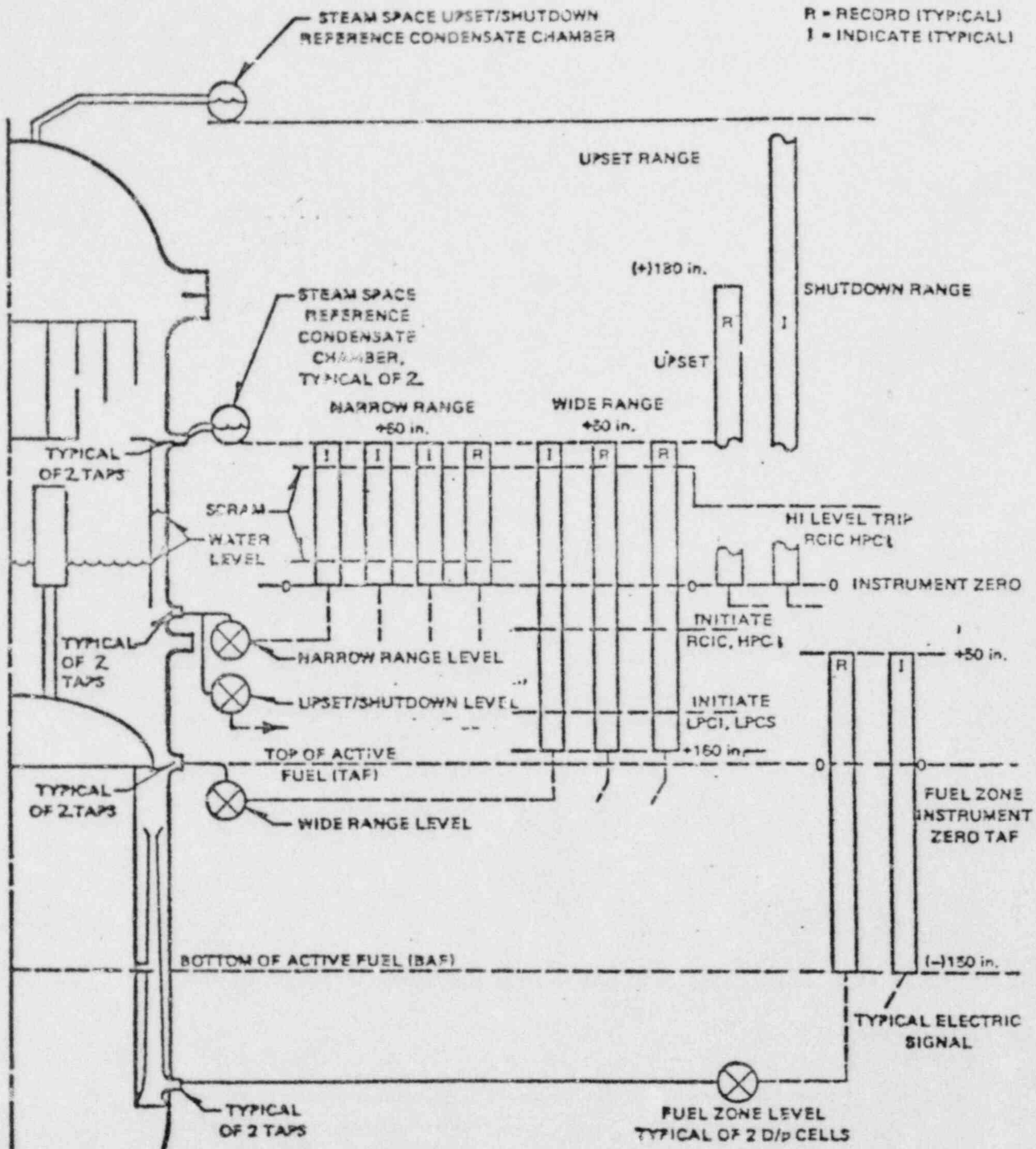


Figure 1. Cold Reference Leg Design



NOTES: 1. SEPARATE D/P CELLS ARE USED FOR NARROW RANGE INDICATION AND TRIP UNITS.

2. INDICATION/RECORD AND TRIP UNITS FOR WIDE RANGE USE COMMON D/P CELLS

Figure 2. Typical Reactor Level Indicators on Reactor Control Panels

Issue Title:

Failures in Vessel Level Sensing Lines Common to Control and Protective Systems.

Issue:

Operating reactor experience indicates that a number of failures have occurred in BWR reactor vessel level reference sensing lines and that, in most cases, the failures have resulted in erroneously high reactor vessel level indication. For BWRs, common reference sensing lines are used for feedwater control and as the basis for establishing vessel level channel trips for one or more of the protective functions (reactor scram, MSIV closure, RCIC, LPCI, ADS, or HPCS initiation). Failures in such sensing lines may cause reduction in feedwater flow and consequential delay in trip within the related protective channel.

If an additional failure, perhaps of electrical nature, is assumed in a protective channel not dependent on the failed sensing line, protective action may not occur or may be delayed long enough to result in unacceptable consequences. This depends on the logic for combining channel trips to achieve protective actions.

It is the NRC position that those reference lines common to the feedwater control function and to any of the protective functions for loss of feedwater events be identified and that the consequences of failures in such reference lines concurrent with the worst additional single failure in the protective systems (reactor scram, MSIV closure, ADS, RCIC, HPCS/HPCI, LPCI, etc.) or their initiation circuits by analyzed.

Response:

The following response was prepared by LRG II and is applicable to CPS. The entire response, including that portion for relay plants is submitted because some of the information provided for relay plants also applies for solid state plants.

Relay Plants (Perry, RiverBend)

In connection with Grand Gulf review, Question J (9/81), this scenario was analyzed in detail for the 251-sized plant. An investigation was also performed to determine differences, if any, respecting the remaining relay BWR/6-238 and BWR/6-218 plants. It was found that such differences were minor and that the discussion and conclusion shown in the Grand Gulf response is generally applicable to all BWR/6 relay design. Regardless of reactor size, the minimum water level is not expected to drop below Level 1.

The worst case scenario is the same as that postulated for Grand Gulf; namely, failure of Division 1 instrument reference line combined with an RPS scram circuit failure in Division 3.

Due to the assumed malfunction of the level sensing device after the break which results in the loss of feedwater flow, the water level decreases and drops below L-2. There is not L3 scram initiated because of the assumed additional electrical failure. The minimum level that the water inventory would reach depends on the following factors: (1) initial power level and power decay characteristics, (2) HPCS+RCIC flow capacities, and (3) bulkwater volume above L-1. Due to the design similarity, the power decay characteristics are similar for these three plants (218,238 and 251). The relative HPCS+RCIC flow capacities (% of NBR FW flow) are also very close to each other. However, the bulk-water-to-power ratios for 238 and 218 plants are 3% larger than that for 251 plants, i.e., relatively more water inventory is available for 238 and 218 plants. This assures that the minimum water level for 238 and 218 plants would not be lower than that for 251 plants.

As mentioned in the Grand Gulf response, even if the minimum water level outside the shroud had fallen to L-1, MSIV closure and the associated position scram would have been initiated. The water level outside the shroud would drop below L-1 for a short time period and then rise again. The water level inside the shroud would still remain above the top of the active fuel at all times.

Based on the foregoing discussion, it is concluded that the consequence of this water level sensing line break event for all relay BWR/6's is less severe than and bounded by the DBA analyzed in Chapter 15 of the FSAR.

Solid State Plants (Clinton, GESSAR)

In BWR/6 solid-state plants, the RPS logic is an 2-out-of-4 channels to scram. Therefore, if one RPS channel reads erroneously high due to the instrument line failure and any additional RPS channel is assumed to fail-short, there are still 2 remaining channels left to accomplish normal scram.

Therefore, there will always be a normal Level 3 scram prior to automatic initiation of either (or both) high-pressure system. It is possible to fail RCIC or HPCS by postulating an instrument line failure and an additional failure in ECCS busses 2 or 3 respectively. However, both systems cannot fail due to a single electrical failure. The postulated worst case scenario is a break in the reference line on the division that is controlling feed-water in conjunction with a failure of the HPCS. Normally, the operator would switch feedwater control from the bad instrument line to the good one as soon as the level mis-match is detected by the annunciator alarm. This would immediately restore normal water level.

Should he neglect to do this, the water level would continue to drop slowly until it reached Level 2. This level would normally initiate both HPCS and RCIC and trip the recirc pumps. However, assuming the additional electrical failure of HPCS, only RCIC will start. Since a successful scram occurred at Level 3, RCIC is sufficient to cause water level to turn around between Level 2 and Level 1 and rise, slowly filling the vessel as power decays.

If still unattended, the vessel level will gradually increase until it reaches Level 8 which will trip the RCIC turbine and assure closure of the main turbine stop valves. Level will drop back toward Level 2 and the cycle will repeat itself being driven by the ever decreasing residual heat decay in the vessel. This will limit vessel level between Level 2 and Level 8 indefinitely until the operator takes the remaining shutdown action. The postulated scenario therefore has no adverse safety consequences for BWR/6 solid-state plants.

FSAR Changes:

None required.

Issue Title:

Containment Atmosphere Monitoring

Issue:

Design of containment atmosphere monitoring system has not been completed and the design details submitted for NRC review.

Response:

A containment atmosphere monitoring system will be installed which is composed of two independent and redundant monitoring subsystems. Each subsystem will draw samples from the containment or drywell through sample lines designed to meet the requirements of ANSI N13.1 and located to obtain representative samples of the atmosphere. The sampled media will be passed through hydrogen and oxygen detectors in each subsystem and returned to the containment. Each monitoring subsystem will operate over a pressure range of negative 1.0 pounds per square inch to positive 30 pounds per square inch. The hydrogen detectors will measure hydrogen over a range of 0 to 10 percent hydrogen concentration by volume and with an accuracy of $\pm$ 10 percent of span. The oxygen detectors will measure oxygen over a range of 0 to 30 percent oxygen concentration by volume and with an accuracy of $\pm$ 10 percent of span. Continuous indication of hydrogen and oxygen from each monitoring subsystem will be provided in the main control room.

The containment atmosphere monitoring system will be designed and manufactured in conformance with the following standards, codes and regulatory guides:

a.	ANSI-N45.2.2-1972	Packaging, Shipping, Receiving, Storage and Handling of Items for Nuclear Power Plants.
b.	ANSI-N45.2.10-1973	Quality Assurance Terms and Definitions.
c.	ANSI-N45.2.12-1974	(Draft 3, Revision 4, Feb. 22, 1974) Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants.
d.	ANSI-N45.2.13-1974	Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants.

Institute of Electrical and Electronics Engineers (IEEE):

IEEE-279 (1971):	Criteria for Protection Systems for Nuclear Power Generating Stations.
IEEE-323 (1974):	Qualifying Class I Electrical Equipment for Nuclear Power Stations.
IEEE-344 (1975):	Guide for Seismic Qualification of Class I Electric Equipment
IEEE-383 (1974):	Standard for Type Test of Class IE Electrical Cables, Field Splices, and Connections for

IEEE-383 (1974): Nuclear Power Generating Stations.

U. S. Nuclear Regulatory Commission Regulatory Guides (NUREG):

a. NUREG 0737 (Nov., 1980) Table II.F.1-3-
Clarification of TMI Action Plan Requirements

b. Regulatory Guide 1.97 (Rev. 2 Dec. 1980) - Table 1, Pages 1.97-9 and 1.97-13

Prior to fuel load, Illinois Power will submit an FSAR amendment covering the detailed design of the CAM system.