HITACHI

GE Hitachi Nuclear Energy

Robert E. Brown
Senior Vice President
Regulatory Affairs

P.O. Box 780
MC A-45
Wilmington, NC 28402
USA

T 910 675 5242
F 910 362 5242
Bob.Brown@ge.com

MFN 07-650

Project No. 710

December 7, 2007

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, D.C. 20555-0001

Subject: **NEDO-31336-A, *General Electric Instrument Setpoint Methodology*, September 1996**

It has come to our attention that a non-proprietary (redacted) version of the accepted proprietary GE Topical Report NEDC-31336P-A, *General Electric Instrument Setpoint Methodology*, September 1996, was not previously provided to the NRC; therefore, the enclosed non-proprietary version is being provided to remedy this situation.

If you have any questions or require additional information regarding the information provided here, please contact me.

Sincerely,

R.E. Brown

Robert E. Brown
Senior Vice President, Regulatory Affairs

D065

NRR

Enclosure:

1. NEDO-31336-A, *General Electric Instrument Setpoint Methodology*, September 1996

cc:	MC Honcharik	USNRC (with enclosure)
	AE Cubbage	USNRC (with enclosure)
	TE Abney	GEH (w/o enclosure)
	Y Dayal	GEH (w/o enclosure)
	JC Kinsey	GEH (w/o enclosure)
	JL Leong	GEH (w/o enclosure)
	RE Miller	GEH (w/o enclosure)
	JA Savage	GEH (w/o enclosure)
	eDRF	0000-0077-1714

Enclosure 1

MFN 07-650

NEDO-31336-A, *General Electric Instrument Setpoint Methodology*, September 1996

GE Nuclear Energy

NEDO-31336-A
Class I
September 1996

General Electric Instrument Setpoint Methodology

W. H. Cooley, Jr.
J. L. Leong
M. A. Smith
S. Wolf

GE Nuclear Energy

175 Curtner Avenue
San Jose, CA 95125

NEDO-31336-A
Class I
September 1996

GENERAL ELECTRIC COMPANY

GENERAL ELECTRIC
INSTRUMENT SETPOINT METHODOLOGY

W. H. Cooley, Jr.
J. L. Leong
M. A. Smith
S. Wolf

Approved by: W.H. Barrentine
Manager
Electrical Design Engineering

Approved by: R.E. Skavdahl
Services General Manager
Engineering Services

Approved by: R. Villa
Manager
Product Licensing

LEGAL NOTICE

This is a nonproprietary version of the document NEDC-31336P-A where the proprietary information of NEDC-31336P-A has been removed. The portions of NEDC-31336P-A that have been removed are indicated by "bars" drawn in the margin of the text of this report. Figures and large equation objects of NEDC-31336P that have been removed are also identified with "bars" where the object was.

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

ILLUSTRATIONS

TABLES

TABLES (Continued)

CONTRIBUTORS

E.M. CHU
M.E. DRISCOLL
E.C. ECKERT
D.L. FOREMAN
R.R. GHOSH
J.M. GRAU
W.K. GREEN
D.A. HAMON
V. HANDA
R. MURALIDHARAN
R.T. REICH
N.C. SHIRLEY
R.A. SIEMER
J.M. USHER
S.A. WILSON
C.H. YEN

ABSTRACT

This report documents an improved methodology developed by the General Electric Company for calculating trip setpoints in instrument systems. The methodology presented includes a generic approach for determining setpoints on the basis of instrument characteristics, bases for confirming these characteristics for selected types of instrument system components, and summaries of the application of the generic approach to selected Boiling Water Reactor protection system setpoints.

This document also includes responses to NRC Staff questions contained in the NRC letter from T. M. Novak to John F. Carolan, "Transmittal of NRC Staff Report on Setpoint Methodology for General Electric Supplied Protection System Instrumentation" (May 15, 1984).

1.0 INSTRUMENT SETPOINT METHODOLOGY

1.1 INTRODUCTION

The determination of nominal trip setpoints must include a consideration of many factors. In the case of setpoints which are directly associated with an abnormal plant transient or accident analyzed in the Final Safety Analysis Report (FSAR), an analytical limit is established as part of the safety analysis. The analytical limit is the value of the sensed process variable prior to or at the point which a desired action is to be initiated. The analytical limit is set so that appropriate licensing safety limits (LSL) are not exceeded, as confirmed by plant performance analysis

Not all parameters have an associated analytical limit (e.g., main steam line radiation monitor). An allowable value, or design basis technical specification limit, may be defined directly based on plant licensing requirements, previous operating experience or other appropriate criteria. The nominal trip setpoint is then calculated from the allowable value, allowing for instrument drift. Where appropriate, a nominal trip setpoint may be determined directly based on operating experience or engineering judgment.

1.2 METHODOLOGY USED TO ESTABLISH NOMINAL TRIP SETPOINTS AND TECHNICAL SPECIFICATION LIMITS

The following discussion relates to the methodology used for establishing setpoints for the protective instrumentation employed in Reactor Protection System (RPS) and Engineered Safety Feature (ESF) channels.

1.2.1 Definitions

1. <u>Nominal Trip Setpoint (NTSP)</u>: The limiting value of the sensed process variable at which a trip action may be set to operate at time of calibration.

2. <u>Allowable Value (AV) (Technical Specification Limit)</u>: The limiting value of the sensed process variable at which the trip setpoint may be found during instrument surveillance. Usually prescribed as a license condition.

3. <u>Analytical Limit (AL)</u>: The value of the sensed process variable established as part of the safety analysis prior to or at the point which a desired action is to be initiated to prevent the safety process variable from reaching the associated licensing safety limit.

4. <u>Licensing Safety Limit (LSL)</u>: The limit on a safety process variable that is established by licensing requirements to provide conservative protection for the integrity of physical barriers that guard against uncontrolled release of radioactivity. Events of moderate frequency, infrequent events, and accidents use appropriately assigned licensing safety limits. Overpressure events use appropriately selected criteria for upset, emergency, or faulted ASME category events.

5. <u>Instrument Channel</u>: An arrangement of components as required to generate a single protective signal. Unless otherwise stated, it is assumed that the channel is the same as the loop.

6. Channel Instrument Accuracy (A_L): The quality of freedom from error of the complete instrument channel with respect to acceptable standards or references. The value specified is the requirement for the combined accuracies of all components in the channel that are used to monitor the process variable and/or provide the trip functions and includes the combined conformity, hysteresis and repeatability errors of all these devices. The accuracy of each individual component in the channel is the degree of conformity of the indicated values of that instrument to the values of a recognized and acceptable standard or reference device (usually National Bureau of Standards traceable), that is used to calibrate the instrument. Channel instrument accuracy does not include the inaccuracies of the calibrating equipment that are used as the standards or references with respect to their errors relative to the true, exact or ideal; nor does it include the allowances for inaccuracies related to the calibration procedures; nor does it include the additional allowances for total channel instrument drift.

7. Channel Calibration Accuracy (C_L): The quality of freedom from error to which the nominal trip setpoint of a channel can be calibrated with respect to the true desired setpoint, considering only the errors introduced by the inaccuracies of the calibrating equipment used as the standards or references and the allowances for errors introduced by the calibration procedures. The accuracy of the different devices utilized to calibrate the individual channel instruments is the degree of conformity of the indicated values or outputs of these standards or references to the true, exact or ideal values. The value specified is the requirement for the combined accuracies of all equipment selected to calibrate the actual monitoring and trip devices of an instrument channel plus allowances for inaccuracies of the calibration procedures. Channel calibration accuracy does not include the combined accuracies of the individual channel instruments that are actually used to monitor the process variable and provide the channel trip function.

8. Channel Instrument Drift (D_L): The change in the value of the process variable at which the trip action will actually occur, due to all causes, between the time the nominal trip setpoint is calibrated and a subsequent surveillance test. The initial design data considers drift to be an independent variable. As field data is acquired, it may be substituted for the initial design information.

9. Sensor (Transmitter): The portion of the instrument channel which converts the process parameter value to an electrical signal.

10. Trip Unit: The portion of the instrument channel which compares the converted process value of the sensor to the trip value, and provides the output "trip" signal when the trip value is reached.

11. Primary Element Accuracy (PEA): The accuracy of the device (exclusive of the sensor) which is in contact with the process, resulting in some form of interaction (e.g., in an orifice meter, the orifice plate, adjacent parts of the pipe and the pressure connections constitute the primary element).

12. Process Measurement Accuracy (PMA): Process variable measurement effects (e.g., the effect of changing fluid density on level measurement) aside from the primary element and the sensor.

13. Normal Environment: The environmental conditions expected during normal plant operation.

14.

15.

16. Instrument Response Time Effects: Delay in the actuation of a trip function following the time when a measured process variable reaches the actual trip setpoint due to time response characteristics of the instrument channel.

17. Transient Overshoot: The difference in magnitude of a sensed process variable taken from the point of trip actuation to the point at which the magnitude is a maximum or a minimum.

18. Steady -State Operating Value (X_o): The maximum or minimum value of the process variable anticipated during normal steady-state operation.

19. Limiting Normal Operating Transient: The most severe transient event affecting a process variable during normal operation for which trip initiation is to be avoided.

20. Licensee Event Report (LER): A report which must be filed with the NRC by the utility when a technical specification limit is known to be exceeded, as required by 10CFR50.73.

21. Operational Limit (OL): The operational value of a process variable established to allow trip avoidance margin for the limiting normal operating transient.

22. Design Basis Event (DBE): The limiting abnormal transient or an accident which is analyzed using the analytical limit value for the setpoint to determine the bounding value of a process variable.

23. Bounding Value (BV): The extreme value of the conservatively calculated process variable that is to be compared to the licensing safety limit during the transient or accident analysis. This value may be either a maximum or minimum value, depending upon the safety variable.

24. Modelling Accuracy: The modeling accuracy may consist of modelling bias and/or modelling variability. The models used by General Electric Safety Analysis have been compared to actual plant test data or more realistic models. Modelling bias is the result of these comparisons when extended to a design basis event and account for whether conservative or nonconservative methods are used. Modelling variability is the uncertainty in the ability of the model to predict the process or safety variable.

25. Limiting Safety System Settings: A term used in the Technical Specifications to refer to Reactor Protection System (nominal) trip setpoints and allowable values.

26. Leave-as-is-Zone: This is the allowable range of as-found instrument setpoints (determined by the individual utility). The derivation of the zone is based on individual utility setpoint methodology results, calibration and surveillance procedures. When an instrument setpoint is found within this region during surveillance testing, it does not have to be reset.

1.2.2 Setpoint Relationships

The steps involved in establishing safety system setpoints are summarized in Figure 1-1. Because of the generic nature of this figure, it is not drawn to any scale and is used solely to demonstrate the qualitative relationship of the various margins.

Margin between calculated plant performance (based on use of the analytical limit as trip setpoint) and the appropriate licensing safety limit shows additional conservatism in the plant design.

The margin between the Nominal Trip Setpoint (NTSP) and the Steady- State Operating Value (SSOV) allows for appropriate channel accuracies modelling accuracies. Where steady-state operation involves a range of values, the more limiting value is used. This margin minimizes unwarranted or spurious system trips.

The flow of requirements in the implementation of the setpoint methodology is described as follows.

The licensing safety limits are based on applicable regulatory and code requirements. These limits provide considerable margin to true public safety limits (e.g., uncontrolled release of radioactivity). Design basis events are also specified.

Figure 1-1 Instrument Setpoint Relationships

Analyses are performed to establish protection system setpoints which assure that appropriate licensing safety limits are not exceeded for design basis events. Trip setpoints used in the analyses are specified as analytical limits. Significant conservatism is built into the licensing basis analytical models and input assumptions. These models and assumptions have been reviewed and approved by the NRC staff and the Advisory Committee on Reactor Safeguards (ACRS). Instrument response time, transient overshoot, and modelling variability are considered in the analysis or shown to be negligible relative to modelling bias.

Instrument component accuracy requirements for each channel which meet or exceed the uncertainties used in the setpoint determination are established for each channel and instruments are purchased. Rated accuracies are evaluated to assure that they are consistent with the instrument uncertainties used in the determination of the allowable values and nominal trip setpoints.

1.2.3 Methods Used to Establish Nominal Trip Setpoints and Technical Specification Limits by Computation

1.2.3.1 Required Data

The following data are required to establish the nominal trip setpoint and technical specification limit:

a. Analytical limit (AL) where applicable. For those cases with no analytical limit, see discussions on establishing setpoints by engineering judgment or historical data (Sections 1.2.4 and 1.2.5).

b. Channel Instrument Accuracy.

c. Channel Calibration Accuracy.

d. Channel Instrument Drift.

e. Process Measurement Accuracy

f. Primary Element Accuracy

1.2.3.1.1 Analytical Limit and Analytical Limit Margins

In all FSAR transient and accident analyses, the automatic protection functions are simulated along with the reactor system. This simulation usually includes the sensor, logic, and any protection actuator devices. In general, nearly all such analyses of transient disturbances involve similar key ingredients:

(a) The transient or accident event is identified from a potential cause and is classified according to likelihood (e.g., moderate frequency to accident).

(b) The reactor operating conditions are identified for which this event is more severe (e.g., full vs. partial power, exposed vs. unexposed cores, etc.). This leads the FSAR case to be on the more severe side of the full range of expected behavior for this event.

(c) Safety-related equipment and protective actions are simulated to be on the least effective side of their allowable performance. The individual setpoint evaluations are in the context of this conservative basis for all other protection actions (e.g., while peak pressure impact and margin may be discussed relative to the neutron flux scram setpoint uncertainties, the safety-relief valve setpoints, steam flow characteristics, and other key parameters are also assumed to be on the conservative side of their expected performance range).

(d) The analytical limit (upper or lower depending on the situation) is derived from plant simulations and analyses. Iterations occur, until a practical set of instruments is specified that satisfies the analytical performance requirements. These coupled requirements are all maintained in change-controlled engineering documents.

(e) Many setpoints/trip functions which are not required for safety have been included in the design for historical reasons. Judgment has often kept a trip function setpoint just out of the range of normal operation, even if it is not closely linked to the preservation of any key safety margin.

(f) Analytical models have been documented and reviewed with the NRC staff, and are subject to conservative General Electric internal controls (e.g., the ODYN code used for many transient events). These models and the procedures related to their use include conservative bias relative to the data available for their qualification, which bounds the conservatism required by NRC review. This required conservatism is documented in the Safety Evaluation Reports (SER) for the codes.

(g) The analytical models always include calculation of transient overshoot of all plant parameters, including the overshoot of the parameter ("actual" and "sensed") being compared to the trip function under review. Sometimes the parameter being sensed to start a protection action is not the direct measure of the critical variables (e.g., peak fuel cladding temperature protection is initiated from sensors on reactor water level, etc.).

(h) All peak (maximum or minimum) values of parameters are compared to the appropriate licensing criteria and compliance must be shown. In many cases, an established licensing criterion itself was chosen to provide extra margin to a true public safety limit, especially for relatively frequent events (e.g., the requirement to avoid boiling transition is known to be well away from any real onset of transient fuel cladding failure).

(i) For each key event that utilizes a trip action from a sensed parameter, the considerations (e.g., modelling accuracy, response time effects, process measurement accuracy, primary element accuracy, and transient overshoot) which were included or excluded can be clearly identified. Uncertainties relative to each pertinent event can be identified, and the sensitivity of the effectiveness of the protective function can be provided. The possibility of results different from the issued FSAR analysis can be presented with and without the expected modelling biases and the results compared to the appropriate criteria. The intent of this effort would be to show from this important viewpoint that constraints on simulation methods provide significant conservatisms, and that the potential impact of any instrument characteristics that have not been included are very small compared to the safety margins that exist.

1.2.3.1.2 Channel Instrument Accuracy

Channel instrument accuracy is a specified system design requirement. The requirements have been developed from evaluation of system functional performance requirements, cumulative field experience from similar applica-

The design allowance encompasses all instrumentation devices (sensors and trip units) in the channel established for a subject trip function.

1.2.3.1.3 Channel Calibration Accuracy

The value specified is the requirement for the combined accuracies of all equipment selected to calibrate the actual monitoring and trip devices of an instrument channel plus allowances for inaccuracies of the calibration procedures.

1.2.3.1.4 Channel Instrument Drift

The specified channel instrument drift allowance is the change in the value at which point the trip action will actually occur, due to any causes except identified accuracy and calibration errors, between the time the nominal trip setpoint is calibrated and a subsequent surveillance test

Methodology used in establishing drift allowances is strongly dependent on the specific application. Regardless of the basis for the setpoint drift allowance, however, its adequacy must be demonstrated empirically and consistently in the field. Actual drift may differ from plant to plant due to environmental factors, maintenance procedures, and trip surveillance frequencies. Consequently, as actual drift data is accumulated, the

1.2.3.2 Allowable Value (Technical Specification Limit)

When actual calibration accuracy data become available, the technical specification limit can be adjusted using this procedure and the new calibration accuracy.

1.2.3.3 Nominal Trip Setpoint

1.2.3.4 Spurious Trip Avoidance Test

1.2.3.5 LER Avoidance Test

1.2.4 Methods Used to Establish Nominal Trip Setpoints and Technical Specification Limits By Engineering Judgement

When it is not practical to apply the analytical techniques discussed above or when the available data is so conservative as to result in unacceptable operating restrictions, engineering judgment is used to establish the nominal trip setpoint and technical specification limit values. The guidelines suggested are those of the zone setting concept.

A two-zone concept is suggested as adequate to establish the nominal trip setpoint and technical specification limit values. The zones specify ranges within which the trip value is adequate for its intended function.

The acceptable trip value zone is a portion of the instrumentation trip range which will have as its midpoint the nominal trip setpoint. The two end points of the zone will be chosen as (1) the allowable value, and (2) a value that will assure spurious trips are avoided. The acceptable trip value zone must be wide enough to allow for normal instrument drift between surveillance intervals.

The LER zone is the portion of the instrumentation trip range beyond the technical specification limit. The LER zone should be established so that when the maximum expected drift has occurred, sufficient margin remains between the technical specification limit and the analytical limit to compensate for instrumentation and calibration accuracies.

An example of the use of engineering judgment where it is not practical to apply computational techniques is the intermediate range monitor (IRM) Neutron Flux Scram. The IRM Neutron Flux Scram exists to shut down the reactor if neutron flux is increasing at a rate that cannot be followed by the operator. There is no analytical basis for differentiating between the nominal trip setpoint and the technical specification limit. A nominal trip setpoint value of 120 divisions is selected to utilize the maximum range of the instrument. This adequacy of selection has been demonstrated through field experience. Allowances for instrument drift are made by providing a two division margin between the nominal trip setpoint and the technical specification limit (122 divisions).

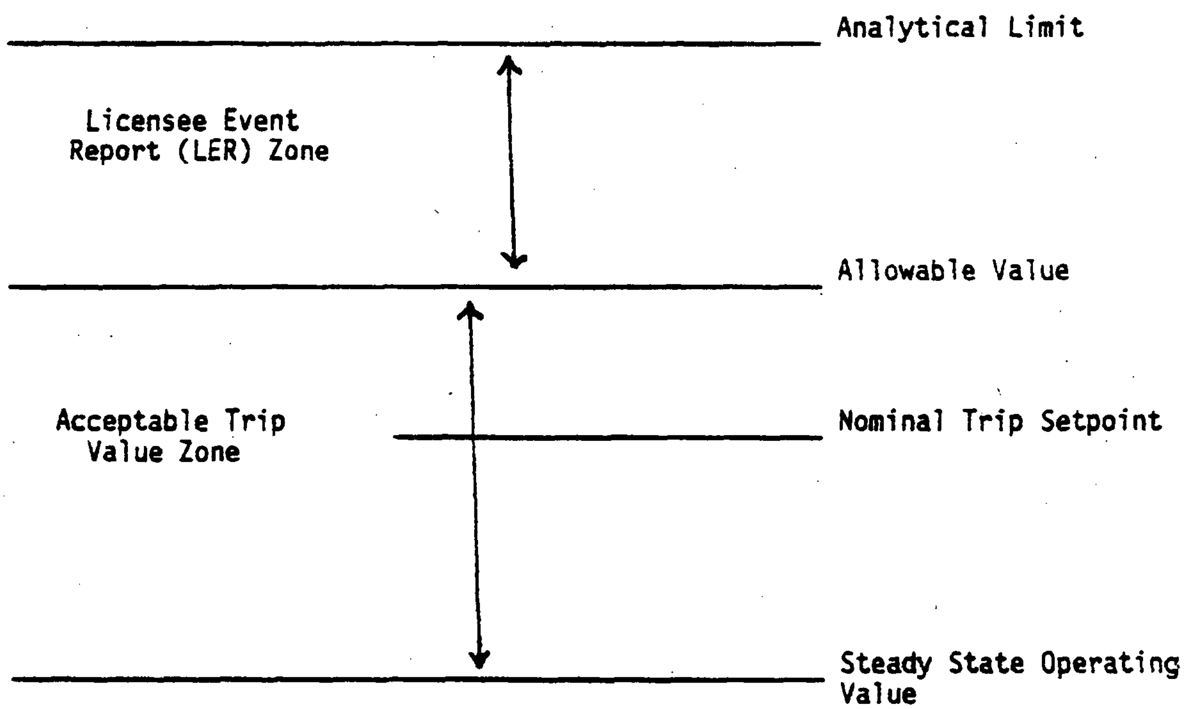


Figure 1-2

METHODS USED TO ESTABLISH NOMINAL TRIP SETPOINTS AND ALLOWABLE VALUE LIMITS BY ENGINEERING JUDGMENT

1.2.5 Methods Used to Establish Nominal Trip Setpoints and Technical Specification Limits by Historical Data

A number of setpoints have non-critical functions, or are intended to provide trip actions related to gross changes in the process variable. These setpoint values have been historically established as acceptable, both for regulatory and operational requirements. The continued recommendation of these historically accepted setpoint values is a third method for establishing nominal trip setpoint and technical specification limit values. This method is applicable when no analytical limit exists. This approach is only valid where the governing conditions remain essentially unaltered from those imposed previously and where the historical values have been adequate for their intended functions.

One way of establishing the technical specification limit, when the nominal trip setpoint is a historically accepted value, is to establish the differential between the nominal trip setpoint and the technical specification limit as the maximum drift permitted between surveillance intervals.

An example of the use of historical data is the Main Steamline Radiation Monitor (MSLRM). The current nominal trip setpoint value (3.0 times full power background) has been established by the NRC. This value is generally accepted as being more than sufficiently low enough to detect a gross release of radioactivity from the core. Allowances for instrument drift are made between the nominal trip setpoint and the technical specification limit (3.6 times full power background).

1.3 CONCLUSION

The determination of instrument setpoints is a disciplined multi-step process which applies conservative methodology at each step to assure positive safety margins. The systematic approach provides assurance that instrumentation uncertainties are recognized and accounted for in design, analysis, and application.

2.0 INSTRUMENT ACCURACY AND DRIFT METHODOLOGY

2.1. INTRODUCTION

The purpose of this section is to describe the calculations used by General Electric to validate instrument accuracy and drift values against system requirements. This methodology is based on the use of Rosemount (1151, 1152-T0280, 1153 Series B, 1154) or Gould (3018, 3200, 3218) transmitters with Rosemount (510) trip units. It may also be applied to devices whose performance and application match those of Rosemount and Gould.

2.2 METHODOLOGY USED TO VALIDATE INSTRUMENT ACCURACY AND DRIFT VALUES

2.2.1 Definitions

System requirements are generally defined in terms of channel (loop) values:

D_L = Channel (Loop) Instrument Drift

A_L = Channel (Loop) Instrument Accuracy

C_L = Channel (Loop) Calibration Accuracy

2.2.2 Temperature Effect on Transmitter Accuracy and Drift

In reviewing General Electric Environmental Interface Specifications, the following data were found on the normal temperature range for transmitters:

A. Generic BWR 4/5 - 40° to 104°F
B. Generic BWR/6 - 40° to 90°F

2.2.3 Transmitter Accuracy

2.2.4 Trip Unit Accuracy

2.2.5 Transmitter Drift

2.2.6 Trip Unit Drift

2.3 ADDITIONAL DEVICES IN INSTRUMENT CHANNEL

e

2.4 STATIC PRESSURE EFFECT ON TRANSMITTER ACCURACY (ROSEMOUNT AND GOULD)

2.5 SEISMIC EFFECT ON TRANSMITTER ACCURACY (ROSEMOUNT AND GOULD)

2.6 RADIATION EFFECT ON TRANSMITTER ACCURACY (ROSEMOUNT AND GOULD)

2.7 TEMPERATURE EFFECT ON TRANSMITTER ACCURACY AND DRIFT (GOULD)

3.0 INSTRUMENT SETPOINT DESCRIPTIONS

The following section contains descriptions of the instrument functions for which credit is taken in the FSAR Chapter 6 or 15 analyses. Each subsection contains discussion of the purpose of the instrument, the trip logic initiated by the instrument, how the setpoint is calculated, the analysis that takes credit for the trip, and the assumptions made in the setpoint determination or analysis.

3.1 REACTOR WATER LEVEL 1

3.1.1 Purpose

Level 1 is used to generate initiation signals of low pressure Emergency Core Cooling Systems (ECCS). Under postulated Loss-of-Coolant Accident (LOCA) conditions that could result in abnormally low vessel water levels, fuel cladding integrity must be assured. These trip signals are set high enough to allow time for the low pressure core flooding systems to activate or the reactor vessel to depressurize, if necessary, by activating the Automatic Depressurization System (ADS). The Level 1 setpoint is also low enough that decreases in level resulting from an operational transient will not reach it, even with an additional single failure, (e.g., loss of feedwater flow with a High Pressure Coolant Injection [HPCI]/ High Pressure Core Spray* [HPCS] failure).

In the event of a large break, where the reactor has depressurized to within the low pressure systems capability, the ECCS functions initiated at Level 1 are the Low Pressure Core Spray (LPCS)/Core Spray* (CS) System and the Low Pressure Coolant Injection (LPCI) function of the Residual Heat Removal (RHR) System. ADS initiation is permitted only after the conditions as outlined in Section 3.9 are met. ADS activation reduces reactor pressure and allows subsequent opening of the LPCS and LPCI injection valves which introduce water to cool the core. A Level 1 trip also sends signals to: (1) close the Main Steam Isolation Valves (MSIVs); (2) disconnect non-Class 1E equipment connected to Class 1E power sources; (3) provide initiation signals to start the diesel-generators which serve as standby AC power sources. For Clinton, Perry and Grand Gulf, Level 1 contributes to the initiation of the suppression pool makeup system to add water to the suppression pool and provide a permissive for containment spray initiation.

*The terms LPCS and HPCS apply to BWR/5 and BWR/6 core spray functions. Core Spray (CS) and HPCI are terms used to reference similiar functions for BWR/4 plants.

Level transmitters are utilized to measure differential pressure, an inverse function of reactor vessel water level, to provide an electrical outputs to associated trip units. When the magnitude of the output results in trip signals, the aforementioned functions will be activated on completion of the logic sequence described below.

3.1.2 Trip Logic Description

A sufficient number of Level 1 trip signals must occur within a particular division to ensure that the functions associated with that division will be performed. For those level transmitters providing signals to RHR and CS/LPCS initiation functions, two-out-of-two levels or one-out-of-two-twice mixed (level/drywell pressure) logic is employed, wherein two level instruments or one level and one pressure instrument in one division must sense a trip signal. The MSIV closure functions, associated with additional transmitters, are also controlled by one-out-of-two-twice logic. In this case, a trip unit in either Channel A or C and a trip unit in either Channel B or D must give a Level 1 trip signal. The ADS logic requires (N-of-N) in each ADS subsystem (i.e., all level sensors in one division must agree).

3.1.3 Setpoint Calculations

The instrument setpoint calculation follows the methodology described in Section 1. The system engineer assigns values to the instrument channel accuracy, calibration and drift, based on knowledge of system requirements and instrumentation capabilities. The accuracy and drift are then confirmed using the methods outlined in Section 2. Process Measurement Accuracy (PMA) and Primary Element Accuracy (PEA) are calculated based on the instrument layout. These values (trip accuracy, drift, calibration, PMA, and PEA) are used in calculating the Allowable Value (AV), and the Nominal Trip Setpoint (NTSP) from the Analytical Limit (AL) per the procedure described in Section 1. The results are presented in Table 3.1-1 for a typical plant. The probability of Licensee Event Report (LER) avoidance is then calculated using the methods described in Section 1. Appropriate Level 1 spurious trip avoidance probabilities must be confirmed for loss of feedwater with coincident HPCI/HPCS failure and the Anticipated Transient Without Scram (ATWS) MSIV closure events. Initial data required in either the setpoint calculation or the determination of trip avoidance probabilities include the following:

Analytical Limit (AL): The limit is specified as approximately 12 inches above the Top of Active Fuel (TAF), so that the Peak Clad Temperature (PCT) does not exceed 2200°F. The Design Basis Event (DBE) is the limiting break of the recirculation line.

Operational Limit: The operational limit is determined from analysis of two transients. The first is a loss of all feedwater flow, conservatively evaluated with an equipment failure in the HPCS/HPCI System so that makeup water is supplied only by the Reactor Core Isolation Cooling (RCIC) System. The second transient is an ATWS MSIV closure.*

3.1.4. Analysis

For the Design Basis Event, the SAFE, REFLOOD, and CHASTE models (NRC approved licensing evaluation models used in the FSAR analysis) are used to predict the PCT. These models use water level analytical limits to simulate when the safety actions are performed. The results are presented in Table 3.1-1 for a typical plant. Analysis shows that, even if water level recedes beneath the Level 1 Analytical Limit to the transmitter variable leg tap, the PCT will not exceed the prescribed 2200°F limit. The SAFE computer code model is also used to predict the minimum water level for

*The ATWS MSIV closure event applies only to trip avoidance calculations Hope Creek, Limerick, Nine Mile Point 2 and Perry plants.

Table 3.1-1

REACTOR WATER LEVEL 1

*The utility may elect to round off these value.

**The Design Safety Limit is the elevation of the lower wide range instrument tap. LOCA analysis shows that as long as the Level 1 trip occurs, the safety limit of 2200°F for the peak cladding temperature will not be exceeded.

***The models used by General Electric for LOCA analysis have a known conservative modelling bias of several hundred degrees.

****Actual margin is this value plus several hundred degrees F modelling bias.

loss of all feedwater flow with coincident HPCS/HPCI failure. Inputs to the analysis assume initial reactor conditions at 105% nuclear boiler rated steam flow. RCIC flow is assumed to activate at the Level 2 analytical limit after the maximum specified RCIC system delay (typically 30 seconds).

ATWS water level behavior is modelled with the REDY computer code (NRC approved licensing evaluation model used in FSAR analysis). This ATWS prediction, in association with the ECCS initiation logic is used as an ATWS design criteria.

3.1.5. Assumptions and Uncertainties

The following assumptions are made in the setpoint determination:

(1)

(2)

(3)

(4)

(5)

(6)

3.2 REACTOR WATER LEVEL 2

3.2.1 Purpose

A Level 2 trip indicates that a reactor transient or Loss of Coolant Accident (LOCA) is occurring, with an associated water level drop. Functions initiated by Level 2 trip consist of Recirculation Pump Trip (RPT),* Reactor Core Isolation Cooling (RCIC) System, and High Pressure Coolant Injection** (HPCI) System or High Pressure Core Spray** (HPCS) System and closure of some of the primary system and containment isolation valves. The Redundant Reactivity Control System* (RRCS) is also initiated for plants required to address for Anticipated Transient Without Scram (ATWS).

The Level 2 setpoint is high enough that for complete loss of feedwater flow the RCIC system flow will be sufficient to avoid initiation of low pressure Emergency Core Cooling Systems (ECCS) at Level 1. RCIC alone is assumed to operate (failure of HPCI/HPCS), since it is the most limiting inventory supply system initiated on Level 2. The setpoint is also low enough that, after a scram caused by a Level 3 trip with no loss of feedwater flow, the RCIC and HPCS/HPCI systems will not be initiated.

Level transmitters are utilized to measure differential pressure (an inverse function of reactor vessel water level) to provide electrical outputs to associated trip units. When the magnitude of the output results in trip signals, the aforementioned functions will be activated on completion of the logic sequence described as follows.

*Plants that have Redundant Reactivity Control System (RRCS) do not have a separate Recirculation Pump Trip, it is performed by RRCS. Plants with RRCS include Limerick, Nine Mile Point 2, Perry, Hope Creek and Grand Gulf (after first refueling).

**HPCI functions at Level 2 apply to all BWR 4 plants. HPCS applies to BWR/5 and BWR/6 plants.

3.2.2 Trip Logic Description

A sufficient number of Level 2 trip signals must occur within a particular division to ensure that the functions associated with that division will be performed. Signals required to initiate RPT, RCIC, HPCS and HPCI functions use one-out-of-two taken twice logic; two-out-of-two logic is used to initiate RRCS. The logic for containment isolation varies depending upon the system.

3.2.3 Setpoint Calculations

The instrument setpoint calculations follow the methodology described in Section 1. The system engineer assigns values to the instrument channel accuracy, calibration accuracy and drift, based on knowledge of system requirements and instrumentation capabilities. The accuracy and drift are then confirmed using the methods outlined in Section 2. Process Measurement Accuracy (PMA) and Primary Element Accuracy (PEA) are calculated based on the type of instrument supplied and instrument layout. These values (trip accuracy, drift, calibration, PMA, and PEA) are used in calculating the Allowable Value (AV) and the Nominal Trip Setpoint (NTSP) from the Analytical Limit (AL) and an example is given in 3.2-1. The probabilities of Licensee Event Report (LER) and spurious trip avoidance are then calculated using the methods described in Section 1. Initial data required in the setpoint calculation or the determination of the trip avoidance includes the following:

> <u>Analytical Limit</u>: The limit is specified so that the volume of water at Level 2 is sufficient coupled with action of RCIC (the most limiting inventory supply system initiated on Level 2) for transients involving loss of all normal feedwater flow to avoid initiation of low pressure systems at Level 1. The Level 2 setpoint is used in Loss of Coolant Accident (LOCA) analysis, and the Maximum Average Planar Heat Linear Generation Rate (MAPLHGR) is set so that the Peak Clad Temperature (PCT) remains below the appropriate safety limit of 2200^{o}F. The Design Basis Event (DBE) is the limiting break of the recirculation line.

Table 3.2-1

REACTOR WATER LEVEL 2

*The models used by General Electric for LOCA analysis have a known conservative modelling bias of several hundred degrees.
**Actual margin is this value plus several hundred degrees F modelling bias.

Operational Limit: The operational limit is the minimum water level established from analysis of a turbine trip or generator load rejection (the limiting operational transient).

3.2.4 Analysis

For the Design Basis Event the SAFE, REFLOOD and CHASTE computer code models (NRC approved licensing evaluation models used in the FSAR analysis) are used to predict the PCT following a simulated scram at the Level 3 analytical limit and ECCS injections at appropriate Level 2 and Level 1 analytical limits. Since the DBE for Level 2 is the same as for Level 1, the bounding values provided in Table 3.2-1 for a sample plant are the same values reported for Level 1.

The ATWS analysis is also performed assuming the appropriate trip actions (detailed in Section 3.6) are initiated at the Level 2 analytical limit. The REDY code (NRC approved licensing evaluation model used in FSAR analysis) is used to simulate the transient.

3.2.5 Assumption and Uncertainties

The following assumptions are made in the setpoint determination:

(1)

(2)

(3)

(4)

(5)

(6)

3.3 REACTOR WATER LEVEL 3

3.3.1 Purpose

A Level 3 trip indicates that the water level in the reactor vessel has dropped, and a continued decrease in level would cause steam to bypass the seal skirts of the separators or dryers. Generally, this is indicative of a significant problem with the level control system or reactor feedwater system. Under these circumstances, reactor scram is initiated by a Level 3 Reactor Protection System (RPS) trip to substantially reduce steam production. The Reactor Water Cleanup system is isolated when a Level 3 trip signal is received. If the Residual Heat Removal (RHR) system is operating in the shutdown cooling mode, the isolation valves on the RHR system suction piping are also closed to prevent further loss of vessel water inventory via that path. Level 3 trip also serves as a permissive signal for initiation of the Automatic Depressurization System (ADS) to allow activation of the low pressure Emergency Core Cooling Systems (ECCS). The Level 3 signal provides confirmation that the reactor vessel water level is low; ADS is not activated until Level 1 is reached.

Level transmitters are utilized to measure differential pressure, an inverse function of reactor vessel water level and provide an electrical outputs to associated trip units. When the magnitude of the output results in trip signals, the aforementioned will be activated on completion of the logic sequence described below.

3.3.2 Trip Logic Description

A sufficient number of Level 3 trip signals must occur within a particular division to initiate the functions associated with that division. Level transmitters corresponding to ADS functions use one-out-of-two logic, wherein either instrument in the 2 divisions of ADS must sense a trip signal. The RPS functions are associated with four additional transmitters that employ one-out-of-two-twice logic. In this case, a transmitter in either

Channel A_1 or A_2 and a transmitter in either Division B_1 or B_2 must receive a Level 3 trip signal to initiate the RPS functions for BWR/4 and BWR/5 plants and channels A or C and B or D for BWR/6 plants. For Clinton, (the only solid state plant), the RPS logic is two-out-of-four. The isolation valves are closed after receipt of two-out-of-two Level 3 signals in either division.

3.3.3 Setpoint Calculations

The instrument setpoint calculations follow the methodology described in Section 1. The system engineer assigns values to the instrument channel accuracy, calibration accuracy and drift, based on knowledge of system requirements and instrumentation capabilities. The accuracy and drift are then confirmed using the methods outlined in Section 2. The Process Measurement (PMA) and Primary Element Accuracies (PEA) are calculated based on the instrument layout. These values (trip accuracy, drift, calibration, PMA and PEA) are used in calculating the Allowable Value (AV) and the Nominal Trip Setpoint (NTSP) from the Analytic Limit (AL) using the methodology in Section 1. The probabilities of Licensing Event Report (LER) avoidance and spurious trip avoidance are then calculated using the methods described in Section 1. An example is presented in Table 3.3-1. Initial data required in the setpoint calculation or the determination of trip avoidance probabilities include the following:

<ins>Analytical Limit</ins>: Specified so that during normal operation seal skirts of the separators and dryers are not uncovered and so that the quantity of coolant following a Level 3 scram is sufficient (coupled with actions of other inventory supply systems) for transients involving loss of all normal feedwater flow to avoid initiation of the low pressure ECCS systems at Level 1. The Level 3 setpoint is used in Loss of Coolant Accident (LOCA) analysis, which determines the Maximum Average Planar Linear Heat Generation Rate (MAPLHGR). This assures that the Peak Clad Temperature (PCT) remains below the appropriate safety limit. The Design Basis Event (DBE) is the limiting break of the recirculation line.

Table 3.3-1

REACTOR WATER LEVEL 3

*The models used by General Electric for LOCA analysis have a known conservative modelling bias of several hundred degrees.
**Actual margin is this value plus several hundred degrees F modelling bias.

Operational Limit (OL): The OL is the minimum water level established from analysis of the limiting operating transient, corresponding to one feedwater pump trip.

3.3.4 Analysis

For the DBE, the SAFE, REFLOOD and CHASTE computer code models (NRC approved licensing evaluation models used in the FSAR analysis) are used to predict the PCT following a simulated scram at Level 3 analytical limit and ECCS injections at appropriate Level 2 and Level 1 analytic limits.

Analysis shows that, even if water level recedes beneath the Level 1 analytical limit to the variable leg tap, the PCT will not exceed the prescribed 2200°F safety limit. The inputs to the analysis assume initial reactor conditions at 105% nuclear boiler rated steam flow. The Low Pressure Coolant Injection system (LPCI) injection valve is assumed to fail (the limiting single failure).

3.3.5 Assumptions and Uncertainties

The following assumptions are made in the determination of the setpoint:

(1)

(2)

(3)

(4)

(5)

(6)

3.4 REACTOR WATER LEVEL 8

3.4.1 Purpose

A Level 8 trip signal indicates that the reactor water level in the vessel has increased and protective actions are initiated to prevent further vessel overfill. The trip signal is selected low enough to protect the turbine against gross carryover of moisture and to provide adequate core thermal margins during abnormal events. Functions activated with this signal include closure of main turbine valves, trips of reactor feedwater pumps or turbines (depending upon feedwater system design), trip of Reactor Core Isolation Cooling (RCIC) system and trip of High Pressure Coolant Injection (HPCI) or High Pressure Core Spray (HPCS) Systems*. Reactor scram by the Reactor Protection System (RPS) may also be included in the Level 8 trip actions** so that the Minimum Critical Power Ratio (MCPR) is maintained above the safety limit MCPR, especially during the feedwater controller failure (maximum demand) transients.

The Level 8 signals are generated from two different reactor water level measurement systems. They are the narrow water range which has a range of 60 inches (or approximately Level 3 to above Level 8) and the wide water range which has a range of 210 or 220 inches (or approximately top of active fuel to above Level 8). The trip actions that are performed by each water level measurement system are outlined in Table 3.4-1.

Level transmitters are utilized to measure differential pressure, an inverse function of reactor vessel water level, and to provide electrical outputs to associated trip units. When the magnitude of the output results in trip signals, the aforementioned functions will be activated in accordance with the initiation logic described as follows.

*HPCS is applicable to BWR/5 and BWR/6 plants, HPCI is for BWR/4 plants.
**Direct scram at Level 8 occurs only for BWR/6. BWR/4 and BWR/5 plants receive a scram signal from the main turbine trip.

Table 3.4-1
LEVEL 8 TRIP ACTIONS PERFORMED

Plant	Narrow Range	Wide Range
Perry	Reactor Scram RCIC Main Turbine Feedwater	HPCS
Clinton	Reactor Scram RCIC Main Turbine Feedwater	HPCS
Grand Gulf	Reactor Scram RCIC Main Turbine Feedwater	HPCS
River Bend	Reactor Scram RCIC Main Turbine Feedwater	HPCS
Nine Mile Point 2	Main Turbine Feedwater	HPCS RCIC
Fermi 2	Main Turbine Feedwater	HPCI RCIC
Hope Creek	Main Turbine Feedwater	HPCI RCIC
Limerick	Main Turbine Feedwater	HPCI RCIC

3.4.2 Trip Logic Description

A sufficient number of Level 8 trip signals must occur within a particular division to ensure that the functions associated with that division will be performed. For those level transmitters corresponding to both RCIC and HPCI/HPCS functions, two-out-of-two logic is employed; plants with Redundant Reactivity Control System (RRCS)* use one-out-of-two-twice logic. Main turbine stop valve and feedwater pump/turbine trips utilize two-out-of-three logic (except Fermi 2 and Limerick which uses one-out-of-two-twice logic). Reactor scram (RPS) functions for BWR/6 plants only, are initiated with one-out-of-two-twice logic (i.e., channel A or C and channel B or D must sense a trip signal). Clinton uses two-out-of-four logic for the scram function.

3.4.3 Setpoint Calculations

The instrument setpoint calculations follow the methodology described in Section 1. The system engineer assigns values to the instrument channel accuracy, calibration and drift, based on knowledge of system requirements and instrumentation capabilities. The accuracy and drift are then confirmed using the methods in Section 2. Process Measurement Accuracy (PMA) and Primary Element Accuracy (PEA) are calculated based on the instrument layout. These values (trip accuracy, drift, calibration, PMA and PEA) are used in calculating the Allowable Value (AV) and the Nominal Trip Setpoint (NTSP) from the Analytical Limit (AL). The probabilities of Licensee Event Report (LER) avoidance and spurious trip avoidance are then calculated using the methods in Section 1. An example is presented in Table 3.4-2. Initial data required in the setpoint calculation or the determination of trip avoidance probabilities include the following:

---

*The RRCS plants are Hope Creek, Limerick, Nine Mile Point 2, and Perry.

Table 3.4-2

REACTOR WATER LEVEL 8

NARROW RANGE	WIDE RANGE

*Although the setpoint calculations produce different values for these channels the utility may elect to use a single setpoint for both, consistent with historical practice.

**There is no safety analysis performed which takes credit for the wide range Level 8 trips.

Analytical Limit: Specified at approximately the top of the steam separators near the upper limit of the region where acceptable steam carryover occurs. The Design Basis Event (DBE) is the feedwater controller failure transient postulated on the basis of a single failure of a control device that can directly cause an increase in coolant inventory by increasing the feedwater flow. The most severe applicable event is a feedwater controller failure to maximum flow demand, where the feedwater controller is forced to its upper limit at the beginning of the event.

Operational Limit: The maximum water level during the limiting operational transient which results from trip of one recirculation pump.

3.4.4 Analysis

The DBE was analyzed with the REDY computer code for Clinton and the ODYN code (NRC approved licensing evaluation models used in the FSAR analysis) for other plants. The transient is initiated from 105% Nuclear Boiler Rated (NBR) steam flow for all plants except Fermi 2 which is initiated from 102% NBR power. Feedwater flow is increased to its upper limit at the start of the transient to represent the simulated failure of the feedwater controller. Appropriate delays due to sensor and logic are considered in the evaluation. The improved SCAT and ISCOR codes (NRC approved licensing evaluation models used in the FSAR analysis) are used to determine the Minimum Critical Power Ratio (MCPR) during the transient and demonstrate adequate margin to the Safety Limit MCPR.

3.4.5 Assumptions and Uncertainties

The following assumptions are made in the setpoint determination:

(1)

(2)

(3)

(4)

(5)

(6)

3.5 REACTOR VESSEL HIGH PRESSURE

3.5.1 Purpose

The reactor vessel pressure must be maintained within the limits precribed by the ASME Boiler & Pressure Vessel Code, Section III. If pressure rises to a preset high value, a trip signal to the Reactor Protection System (RPS) will initiate reactor scram to shut down nuclear heat generation. Reactor scram is initiated by high pressure if other signals have failed to scram the reactor to limit the effect of positive pressure on reactor power and provide assurance that reactor vessel integrity will be maintained.

3.5.2 Trip Logic Description

The reactor vessel steam dome pressure is monitored by four pressure transmitters. There are a total of four trip units providing a high pressure trip; (one each for channels A, B, C and D, for BWR/6 plants and A_1, A_2, B_1, and B_2 is the designation used for BWR/4 and 5 plants). The trip logic for reactor scram is arranged in one-out-of-two-twice logic except for Clinton which has two-out-of-four logic to perform the trip function.

3.5.3 Setpoint Calculation

The instrument setpoint calculations follow the methodology described by Section 1. The system engineer assigns values to instrument channel accuracy, calibration accuracy, and drift based on a knowledge of the system requirements and instrumentation capabilities. The accuracy and drift are then confirmed using the methods in Section 2. Process Measurement Accuracy (PMA) and Primary Element Accuracy (PEA) are also determined.

The Allowable Value (AV) and Nominal Trip Setpoint (NTSP) are then calculated using the methods described in Section 1. The probabilities of Licensee Event Report (LER) and spurious trip avoidance are also calculated, using the methods described in Section 1. An example is presented in Table 3.5-1. The operational limit for spurious trip avoidance is established from analysis of a turbine control system pressure regulator switching event (the limiting operational transient).

3.5.4. Analysis

The Design Basis Event (DBE) for the high pressure scram setpoint is the closure of the Main Steam Isolation Valves (MSIVs) with pressure scram. The normal scram path associated with MSIV position switches and high neutron flux are assumed failed.

The ODYN code (NRC approved licensing evaluation model used for the FSAR analysis) is used to simulate this transient. The transient is initiated from 105% Nuclear Boiler Rated (NBR) steam flow, and a conservative closure time of 3 seconds is utilized (compared to a nominal range of 3 to 5 seconds). An appropriate maximum scram delay (sensor plus logic) time is also included in the ODYN simulation.

3.5.5 Assumptions and Inaccuracies

The following assumptions are made in the setpoint calculations:

(1)

(2)

Table 3.5-1

HIGH PRESSURE SCRAM

*The utility may elect to round off those values.
**The reactor vessel bottom pressure corresponding to ASME emergency event limits.

(3)

(4)

(5)

(6)

3.6 REACTOR VESSEL HIGH PRESSURE ATWS RPT

3.6.1 Purpose

In the event of assumed failure of the normal scram paths associated with the Reactor Protection System (RPS) vessel high pressure trip, the Main Steam Isolation Valve (MSIV) position switches and the high neutron flux trips, the Reactor Pressure Vessel (RPV) high steam dome pressure Anticipated Transient Without Scram Recirculation Pump Trip (ATWS RPT) signal is initiated (if reactor pressure rises to a preset high value).

This signal also does the following for Limerick, Perry, Hope Creek, and Nine Mile Point 2, which are equipped with the Redundant Reactivity Control System (RRCS):

(1) Initiates Alternate Rod Insertion (ARI).
(2) Contributes to initiation (after a time delay) of feedwater flow runback.
(3) Contributes to initiation (after a time delay) of the Standby Liquid Control System (except Perry with manual initiation) and isolation of the Reactor Water Cleanup System (RWCU).

For Fermi 2, Clinton and Grand Gulf*, the high pressure signal initiates ARI and RPT only.

The trip of the recirculation pumps early in the event will result in reduction of core flow which creates voids, thereby reducing the power generation.

* ARI to be installed at a later date at Grand Gulf.

3.6.2 Trip Logic Description

There are four pressure transmitters and trip devices which provide the protective trip function. Each pressure transmitter functions as part of a circuit that monitors reactor vessel steam dome pressure and provides a trip signal in its assigned electrical division (except River Bend, Clinton and Grand Gulf*, which do not use assigned divisional power) if the pressure rises to a predetermined high value. The presence of two such trip signals in the same electrical division will:

(1) Trip recirculation pumps (for Limerick, River Bend, Clinton, Fermi 2, Hope Creek plants and Grand Gulf* design).

or

(2) Trip recirculation pumps from the normal power supply, which transfers input power to the low-frequency motor-generator (LFMG) sets, and then will trip the recirculation pumps from the LFMG sets after a time delay if the Average Power Range Monitors (APRMs) still read high (for Perry, and Nine Mile Point 2).

3.6.3 Setpoint Calculation

The instrument setpoint calculation follows the methodology described in Section 1. The system engineer assigns values to the instrument channel accuracy, calibration, and drift, based on knowledge of the instrument capabilities and system requirements. The instrument accuracy and drift values are then confirmed using the the methods outlined in Section 2. Analysis is also performed to determine the Process Measurement Accuracy (PMA) and Primary Element Accuracy (PEA). These values are then used to determine the Allowable Value (AV), and the Nominal Trip Setpoint (NTSP) from the Analytical Limit (AL). An example is given in Table 3.6-1. The probabilities of spurious trip avoidance and Licensee Event Report (LER) avoidance are also calculated using the methods described in Section 1.

---

* The current and future Grand Gulf design provides that either of the two trip signals per trip system will enable the safety function of the trip system.

Table 3.6-1

REACTOR VESSEL HIGH PRESSURE ATWS RPT

*The utility may elect to round off this value.

**The reactor vessel bottom pressure corresponding to ASME emergency event limits for active components. For passive components the maximum pressure limit is 1500 psig.

3.6.4 Analysis

The Design Basis Event for the ATWS RPT setpoint is the Main Steam Isolation Valve (MSIV) closure with a failure to scram. The normal scram paths associated with MSIV position switches, high neutron flux and high dome pressure are assumed to have failed. The safety limit is peak pressure at the RPV bottom of 1375 psig for active components, and 1500 psig for passive components.

The REDY code (NRC approved licensing evaluation model used in FSAR analysis) is used to simulate this transient. The initial condition is 100% Nuclear Boiler Rated (NBR) steam flow. A nominal four second MSIV closure time is used.

The ATWS analyses for four of the plants (Perry, Nine Mile Point 2, Limerick, and Hope Creek) are plant specific. The River Bend, Grand Gulf* and Fermi 2 results are estimated values based on generic plant analysis with adjustments for plant specific total relief valve capacities.

3.6.5 Assumptions and Uncertainties

The following assumptions are made in the setpoint determinations:

(1)

(2)

(3)

(4)

(5)

(6)

3.7 MAIN STEAM SAFETY/RELIEF VALVE - RELIEF* /LOW-LOW SET

3.7.1 Purpose

The main steam Safety/Relief Valves (SRVs) perform several functions. Some of these functions require a trip signal (from reactor vessel dome pressure) to open and close a sequence of SRVs at valve inlet pressures below the safety (spring) actuation setpoints.

The first of these trip setpoints is designated as the "relief" setpoint for BWR/5 and BWR/6 plants that use Crosby and Dikkers valves (Table 3.7-1). On these plants, the relief setpoints are 3 to 5 sequential values, with one or more valves at each setpoint. One or more valves will open during reactor pressure transients. The selected setpoints are such that, for the limiting transients, ASME Code limits on peak vessel pressure (vessel bottom pressure) will not be exceeded when credit is taken for SRV actuation.

The second trip setpoint, designated as "Low-Low Set" (LLS) relief setpoint, is used for all plants (BWR/6) with Mark III containments to eliminate containment loading due to repeated multiple SRV actuations for transient events. For Mark I containments (Fermi 2 and Hope Creek), LLS is designed to assure that after initial opening and closing of SRVs, actuations will not occur within the time interval required for the SRV discharge line water leg to decrease to a level such that containment loading is acceptable. In this case, the intent is to reduce loads on SRV discharge piping and associated loads on the torus, which can be large if SRV actuation occurs with a large water leg in the discharge piping.

---

*BWR/4 plants (Limerick, Fermi 2, and Hope Creek) with Target Rock SRVs are considered to perform safety instead of relief functions. The associated safety setpoints are discussed in the SRV Safety Setpoint Section. Fermi 2 and Hope Creek do have LLS functions which are included in this report.

Table 3.7-1

SAFETY/RELIEF VALVE INFORMATION

	BWR model	Containment MARK	SRV Mfr.	Number of SRV	Low-Low Set	Auto Relief*
Perry	6	III	Dikkers	19	Yes	Yes
River Bend	6	III	Crosby	16	Yes	Yes
Clinton	6	III	Dikkers	16	Yes	Yes
Grand Gulf	6	III	Dikkers	20	Yes	Yes
Nine Mile Point 2	5	II	Dikkers	18	No	No
Limerick	4	II	T/R	14	No	No
Fermi 2	4	I	T/R	15	Yes	No
Hope Creek	4	I	T/R	14	Yes	No

*Yes indicates plants for which credit has been taken for the relief mode of actuation for ASME code required overpressure protection analysis.

Both types of loading are reduced by LLS logic circuitry that arms preselected valves when reactor pressure transients are expected to result in at least one SRV opening. The LLS logic permits extended vessel depressurization cycles through the preselected valves. This results in longer time intervals between subsequent vessel repressurization and valve reopening. It eliminates or acceptably spreads out subsequent multiple valve reopenings, thereby reducing containment design loads. In addition, the LLS feature reduces the required number of SRV cycles, which results in a reduction of the total containment and SRV fatigue duty cycles.

3.7.2 Trip Logic Description

SRVs with relief functions (Crosby and Dikkers valves) will be opened when their relief setpoints are exceeded during a pressure transient. For Nine Mile Point 2 and BWR/6 plants, each group of valves at one setpoint is ganged together using shared logic. In addition, BWR/6's have redundant logic. The valves equipped with the LLS functions are also armed to function at their LLS setpoints as described below.

The LLS arming logic is designed to prevent the valves from prematurely actuating during normal plant operation, since the opening setpoints for the LLS function are in the pressure range of normal reactor operation. For the BWR/6's, the LLS valves are armed after any one SRV receives a signal to open in the normal relief mode. For Fermi 2, the LLS valves are armed by coincident signals indicating actuation of any SRV and high reactor pressure scram. For Hope Creek, the LLS valves are armed by coincident signals indicating that the high LLS valve setpoint and high reactor pressure scram setpoint have been reached.

The logic design assures that a single failure shall not prevent any LLS valve from operating or cause inadvertent seal-in of the LLS logic. Once LLS is armed, the control logic of the LLS uses the steam dome pressure instrumentation to electrically control the SRV solenoid valves so that only the LLS valves open and close at their assigned LLS setpoints. The control logic governs as long as the arming logic remains sealed in. The logic seal-in is annunciated and remains in effect until the operator manually resets it.

3.7.3 Setpoint Calculations

The instrument accuracy, calibration and drift are assigned values based on knowledge of the instrumentation and system requirements by the system engineer. The values for instrument accuracy and drift are confirmed using the methods in Section 2. The AV and NTSP are then calculated using the methods in Section 1 and an example is included in Tables 3.7-2 and 3.7-3. The Licensee Event Report (LER) avoidance criterion is also applied following Section 1.

3.7.4 Analysis

For BWR/6 plants with redundant pressure-sensing logic, the SRV relief function is part of the reactor overpressure protection system to satisfy requirements of Section III of the ASME Boiler and Pressure Vessel Code. The NRC has adopted the ASME Code as part of their requirements in the Code of Federal Regulations (10CFR50.55a). Accordingly, limited credit is allowed for the dual purpose safety/relief valves in their ASME code qualified modes of relief operation. The appropriate analyses for limiting SRV transient events and Anticipated Transients Without Scram (ATWS) are presented separately in the following subsections.

3.7.4.1 Relief Function for Transient Events

For the BWR/6 plants, the overpressure protection analysis is performed with credit for half of the SRVs opening at the SRV relief function and the remainder opening at the safety function setpoints. Hence, for these

Table 3.7-2

MAIN STEAM SAFETY/RELIEF VALVE - RELIEF SETPOINTS

GROUP		
1st	2nd	3rd

*The utility may elect to round off these values.
**The reactor vessel bottom pressure corresponding to ASME moderate frequency event limits.

Table 3.7-3

SRV LOW-LOW SET

1ST		2ND		3RD	
OPEN	CLOSE	OPEN	CLOSE	OPEN	CLOSE

*The utility may elect to round off these values.
**This safety corresponds to the nominal setpoint of the first group of relief valves.

plants, the Design Basis Event (DBE) for the SRV relief setpoint is the most severe vessel overpressure transient event. Both the closure of all Main Steam Isolation Valves (MSIV) and a turbine/generator trip with bypass failure are evaluated. The MSIV closure event is slightly more severe when credit is taken only for indirectly derived scrams, while the turbine/generator trip with bypass failure is slightly more severe when credit is taken for direct scram. Hence, the MSIV closure with neutron flux scram is used as the DBE for the SRV relief setpoint.

For Nine Mile Point 2 (a BWR/5 without redundant relief pressure-sensing logic), the FSAR overpressure protection analysis is conservatively performed with credit for the SRV spring safety function only. The DBE for the SRV relief setpoints for this plant is the generator load rejection with bypass failure event (FSAR Chapter 15).

These DBEs were analyzed with the REDY computer code for Clinton and with the ODYN code (NRC approved licensing evaluation models used for FSAR analysis) for the other plants. The applicability of the River Bend FSAR ODYN results to Clinton for pressurization transients is justified in the Clinton FSAR (Section 15.2). Therefore, the River Bend MSIV closure results are applied to Clinton. The transients were initiated from full design power conditions of 105% Nuclear Boiler Rated (NBR) steam flow. The MSIVs are normally specified to close in 3 to 5 seconds. For the analysis, a conservative closure time of 3 seconds was utilized. Protection functions were modeled at their AL values (e.g., high APRM neutron flux scram setpoint). A maximum SRV delay time (including pressure sensor, logic plus valve delay) of 0.4 seconds was also included in the analysis. The results of the relief function analyses are summarized in Table 3.7-2 for a typical plant.

The SRV functions for the MSIV closure event for overpressure protection were modeled as follows:

> Whenever system pressure increases to the relief pressure setpoint of a group of valves having the same setpoint, half of those valves are assumed to operate in the relief mode, opened by the pneumatic power actuation. When the system pressure increases to the valve spring set pressure of a group of valves, those valves not already considered open are assumed to begin opening and to reach full open at 103% of the valve spring set pressure.

3.7.4.2 LLS Function for Transient Events

The DBE for the SRV LLS setpoint is the MSIV closure event with direct scram (FSAR Chapter 5). The SAFE computer code (NRC approved licensing evaluation model used for FSAR analysis) is used to analyze this long term event. The transient is initiated from 105% NBR steam flow. The analysis assumes nominal relief setpoints, nominal LLS setpoints for BWR/6s and analytical limit LLS setpoints for Fermi 2 and Hope Creek, conservative relief opening and closing response and conservative decay heat. The results of the LLS function analyses are summarized in Table 3.7-3 for a typical plant.

3.7.4.3 Relief and LSS Functions for ATWS Events

The main steam SRVs are expected to perform similar functions during Anticipated Transient Without Scram (ATWS) events as during events with scram.

The Safety Limits for ATWS pressurization events are chosen to apply appropriately for active and passive components. General Electric practice has been to design active components for the pressure to which they will be exposed or to perform an assurance-of-function review. The critical components for this review are the SRVs and the MSIVs. These active components are limited to 1375 psig. Other active components have higher limits which were shown through assurance-of-function review. Passive components are limited to Service Level C, ASME Boiler and Pressure Vessel Code, Section III.

The ATWS basis is MSIV closure initiated from 100% NBR conditions. This event has been analyzed with the REDY computer code for Perry, Grand Gulf and Nine Mile Point 2. ATWS analyses have not been done for River Bend, Clinton, and Fermi 2. ATWS analyses for Limerick and Hope Creek are presented in the SRV Safety Setpoint Description. ATWS events are analyzed with all SRV relief functions operable. Bounding values for ATWS events were found to be less limiting than the bounding values for transient events (Subsection 3.7.4.2).

(1) Perry

For Perry ATWS analysis, AL values of relief functions were used for the initial SRV opening. All SRV closures and subsequent openings were then modeled to occur at the NTSP values.

(2) Grand Gulf

For Grand Gulf ATWS analysis, AL values of the setpoints were used in all opening and closing actuations. This was an early analysis and ATWS analytical procedures were subsequently revised to be more realistic for subsequent cycles. This deviation will have no significant impact on the predicted maximum pressure (Bounding Value).

(3) Nine Mile Point 2

For Nine Mile Point 2 ATWS analysis, AL values of the relief functions were used for the initial opening. All SRV subsequent openings were then modelled to occur at the NTSP value plus 8 psi. All SRV closures were modelled to occur at the opening setpoint times the lower limit closing fraction (0.89).

Each group of relief valves at a particular setpoint has two pressure sensors associated with it. Both sensors for each group must provide a signal to initiate opening of the entire group (two-out-of-two logic).

Even though both sensors for a group are set at the same setpoint, in reality they will most likely be spread over some range of values. For the initial opening, the AL is used for each group. For subsequent openings, the setpoints of the two sensors for a given group of values is "spread" around the NTSP by factors based on order statistics and the standard deviation, and the higher of the two values is used as the opening setpoint for the entire group (calculated to be 8 psi higher than the NTSP when the difference between the AL and NTSP values is assumed to be equal to two standard deviations).

3.7.4.4 LLS Function for LOCA Events

The LLS functions for Fermi 2 and Hope Creek are designed to operate for LOCA events. A small break LOCA would fill the drywell with steam, so after each SRV actuation, the vacuum breaker would draw steam instead of air into the SRV discharge line. Condensation of this steam inside the discharge line would result in a higher water leg and thus a longer time for the water leg to return to normal. The vacuum breakers on the SRV discharge line open to equalize the pressure between the SRV discharge line and the drywell, allowing the water leg to return to its normal level. SRV actuation before water level returns to normal could result in high thrust loads.

This potentially high thrust load condition is accounted in the design of the SRV LLS setpoints for Fermi 2 and Hope Creek. The LOCA basis event for these two plants is a small break (0.1 ft^2) with loss of offsite power. The loss of offsite power will result in a loss of power to the MG sets of the Reactor Protection System, causing reactor isolation and subsequent pressurization. This event is initiated from full power (105% NBR steam flow and 104.2% NBR power). The results of this analysis are bounded by the DBE analysis for SRV LLS setpoints (Subsection 3.7.4.2).

The LLS functions of the BWR/6 plants are also designed to operate for LOCA events. For this class of plants, predicted pool boundary containment loads due to second or subsequent multiple valve actuations may exceed the current design basis. Therefore, the LLS logic was designed to eliminate such subsequent actuations of multiple SRVs. Bounding values for the SRV LLS setpoints for LOCA events were found to be less limiting than the bounding values for transient events (Subsection 3.7.4.2).

3.7.5 Assumptions and Uncertainties

The following assumptions are made in the setpoint determination:

(1)

(2)

(3)

(4)

(5)

(6)

3.8 MAIN STEAM SAFETY/RELIEF VALVE - SAFETY

3.8.1 Purpose

BWR/6's and Nine Mile Point 2 use Crosby or Dikkers Safety/Relief Valves (SRVs) and BWR/4's have Target Rock SRVs (see Table 3.8-1), to perform the required pressure relief safety function. The safety function of the SRVs occurs when steam pressure acting on the valve inlet overcomes the spring preload that establishes the setpoint pressure. Upon valve actuation, the reactor primary system high pressure is relieved by discharging steam through the valves and their discharge lines into the suppression pool. The reactor primary system pressure is thus maintained within the limits of Section III of the ASME Boiler and Pressure Vessel Code even in the event of a high pressure transient condition.

3.8.2 Valve Actuation Mechanism

Two to six SRVs are mounted between the reactor pressure vessel and the inboard main steam line isolation valves (MSIVs) on each of the four main steam lines. The actuation mechanism is either direct (at set pressure, steam pressure opens main disc) or pilot actuated (at set pressure, steam pressure opens a pilot valve which triggers main valve opening), depending on the valve design. A description of each actuation mechanism is presented below.

3.8.2.1 Direct Activation

Crosby and Dikkers SRVs are of the direct acting design. River Bend is equipped with Crosby valves, while Perry, Clinton, Grand Gulf and Nine Mile Point 2 have Dikkers valves. These valves have main discs that are loaded directly by a spring that establishes set pressure to keep the SRVs closed. When the main steam line static pressure on the valve disc exerts enough force to overcome the spring preload, the valve opens and remains that way until the main steam line static pressure drops to the range of 89 to 98% of the opening pressure, at which point valve reclosure occurs. Relief

Table 3.8-1

SAFETY/RELIEF VALVE INFORMATION

	BWR model	Containment MARK	SRV Mfr.	Number of SRV	Low-Low Set	Auto Relief*
Perry	6	III	Dikkers	19	Yes	Yes
River Bend	6	III	Crosby	16	Yes	Yes
Clinton	6	III	Dikkers	16	Yes	Yes
Grand Gulf	6	III	Dikkers	20	Yes	Yes
Nine Mile Point 2	5	II	Dikkers	18	No	No
Limerick	4	II	T/R	14	No	No
Fermi 2	4	I	T/R	15	Yes	No
Hope Creek	4	I	T/R	14	Yes	No

*Yes indicates plants for which credit has been taken for the relief mode of actuation for ASME code required overpressure protection analysis.

actuation of these valves covered in a separate discussion, is produced by an air actuator which opens and closes the valve below the spring actuation pressures for all high pressure operational transients.

3.8.2.2 Indirect Pilot Activation

Two-stage pilot-operated SRVs manufactured by Target Rock have been installed at Limerick, Fermi 2 and Hope Creek. This valve design consists of two principal assemblies: (1) the pilot stage assembly, which is the pressure sensing and control element, and (2) the main stage assembly, which provides the steam flow capacity. When the pressure on the pilot disc exceeds a value which exerts enough force to overcome the preload on the pilot disc, the pilot valve opens and allows a differential pressure to be developed across the main stage piston. This causes the main piston with the main disc to stroke open. The pilot disc remains open until the valve inlet pressure drops to the range of 89 to 97% of the opening setpoint, at which point pilot valve closes and initiates closure of the main valve disc.

3.8.3 Setpoint Calculations

The Analytical Limits (AL) for the SRV safety functions are selected such that none of the FSAR transients or accidents results in violation of appropriate safety limits. The allowable setpoint uncertainties are specified to be within the ASME Code Section III limit of 1% of the nominal setpoint. The individual uncertainties delineated in Section 1, attributed to loop accracy, calibration and drift, are lumped in the allowable uncertainty term. This uncertainty term is then subtracted from the AL to determine the Nominal Trip Setpoint. The Allowable Value (AV) and AL are approximately the same and any small difference is either conservative or acceptable (BWR/6 plants), since more than one third of the capacity is provided for the lowest setpoint; whereas, the FSAR analysis takes credit for only one third or less of the relief capacity at each setpoint.

Safety setpoints are typically divided into three to five setpoint categories with anywhere from 2 to 8 valves in a given category. The valve grouping and setpoint values are summarized in Table 3.8-2 for a typical plant.

3.8.4 Analysis

The SRV safety function is part of the vessel overpressure protection system which is designed to satisfy requirements of Section III of the ASME Boiler and Pressure Vessel Code. The NRC has adopted the ASME Code as part of their requirements in the Code of Federal Regulations (10CFR50.55a). The appropriate analyses for limiting SRV transient events and Anticipated Transients Without Scram (ATWS) are presented separately in the following Sections.

3.8.4.1 Safety Function for Transient Events

The Design Basis Event (DBE) for the SRV safety setpoint is the most severe vessel overpressure transient event in which direct scram protection is assumed to have failed. Both the closure of all Main Steam Isolation Valves (MSIV) and a turbine/generator trip with bypass failure are evaluated. The MSIV closure event is slightly more severe when credit is taken only for indirectly derived scrams, while the turbine/generator trip with bypass failure is slightly more severe when credit is taken for direct scram. Hence, the MSIV closure with neutron flux scram is used as the design basis event for the SRV safety setpoint.

These DBEs were analyzed with the REDY computer for Clinton and the ODYN code (NRC approved licensing evaluation models used for FSAR analysis) for the other plants. The applicability of the River Bend FSAR ODYN results to Clinton for pressurization transients is justified in the Clinton FSAR (Section 15.2). Therefore, the River Bend MSIV closure results are applied to Clinton. The transients were initiated from full power conditions of 105% Nuclear Boiler Rated (NBR) steam flow. A maximum valve delay time of 0.4 seconds was included in the analysis for plants with Target Rock SRVs, BWR/4s. No delay time was included for plants with Crosby or Dikkers SRVs (BWR/5's and 6's).

Table 3.8-2

MAIN STEAM SAFETY/RELIEF VALVE - SAFETY SETPOINTS

GROUP		
1st	2nd	3rd

*Some plants exhibit small differences between the analytical limit and allowable value. This is acceptable since more than 1/3 capacity is provided at the lowest setpoint but the analysis assumes equal relief capacity at each setpoint.

**The reactor vessel bottom pressure corresponding to ASME moderate frequency event limits.

For BWR/6 plants which have redundant SRV relief logic, overpressure protection analysis is performed with credit for both the SRV relief and safety functions, as allowed for the dual purpose safety/relief valves in their ASME Code qualified modes of safety operation. For these plants, the SRV functions for the MSIV closure event for overpressure protection were modelled as follows:

> Whenever system pressure increases to the relief pressure setpoint of a group of valves having the same setpoint, half of those valves are assumed to operate in the relief mode, opened by the pneumatic power actuation. When the system pressure increases to the valve spring set pressure of a group of valves, those valves not already considered open are assumed to begin opening and to reach full open at 103% of the valve spring set pressure.

For Nine Mile Point 2, a BWR/5, the FSAR overpressure protection analysis for the DBE is conservatively performed with credit for the SRV safety function only.

For the BWR/4 plants, the FSAR overpressure protection analysis for the DBE is performed with SRV safety function only.

The results of the analyses are summarized in Table 3.8-2 for a typical plant.

3.8.4.2 Safety Function for ATWS Events

The main steam SRVs are expected to perform similar functions in ATWS events as during non-ATWS events. For SRVs with two distinct relief and safety setpoints such as Crosby and Dikkers valves, the ATWS basis utilizes the relief setpoint, and is discussed in the Relief Setpoint Description. The SRV safety function for ATWS design is considered only for the Target Rock Valves on BWR/4s. Therefore, only Limerick and Hope Creek are discussed in this ATWS analysis subsection.

The Safety Limits for ATWS pressurization events are chosen to apply appropriately for active and passive components. General Electric practice has been to design active components for the pressure to which they will be exposed or to perform an assurance-of-function review. The critical components for this review are the SRVs and the MSIVs. These active components are limited to 1375 psig. Other active components have higher limits which were shown through assurance-of-function review. Passive components are limited to Service Level C, ASME Boiler and Pressure Vessel Code, Section III.

The ATWS basis is MSIV closure initiated from 100% NBR conditions. This event has been analyzed with the REDY code (NRC approved licensing evaluation model used in FSAR analysis). The AL values are used for the initial SRV opening setpoints. All subsequent openings are considered at the NTSP values. SRV closing setpoints were taken at 110 psi below the corresponding opening NTSP to more realistically represent the long-term ATWS events after the peak pressure has been mitigated conservatively. Because each of the SRVs operates individually, there will be variation in their actual plant opening. This is accounted for in the analysis by "spreading" the opening setpoints using order statistics. The standard deviation (1 sigma) which is used to accomplish this spreading is 22 psi.

3.8.5 Assumptions and Uncertainties

The following assumptions are used in the setpoint determination:

(1)

(2)

(3)

(4)

(5)

(6)

3.9 ADS AND DRYWELL PRESSURE BYPASS TIMERS

3.9.1 Purpose

Two timers are used to delay initiation of the Automatic Depressurization System (ADS). The ADS timer provides between 90 and 120 seconds delay following trip signals from low water Level 1 and for some plants high drywell pressure. The drywell pressure bypass timer provides additional delay following a trip signal from Level 1 only. These time delays are provided to allow the operator time to terminate ADS actuation and avoid an automatic blowdown if he concludes that reactor water level is being restored or if the operator thinks the signals are erroneous. The operator can delay the ADS by continuously resetting the timer.

The ADS actuation logic in use involves several plant specific variations selected by individual utilities in response to Nuclear Regulatory Commission (NRC) request (NUREG 0737, Item II.K.3.18).

3.9.2 Trip Logic Description

The various logic alternatives in use are described below:

(1) Fermi 2 and Grand Gulf*

When high drywell pressure trip signal is received, it is sealed into the initiation sequence and does not reset even if the high drywell pressure condition clears before Level 1 (low RPV water level) trip signal is received. A subsequent Level 1 trip signal initiates the ADS timer after confirming that Level 3 trip signal is also present (to prevent spurious actuations that could be caused by faulty Level 1 trip signal). Once started, the timer is automatically reset if RPV water level is restored above Level 1 before it times out. The timer will restart if Level 1 trip signal occurs again. The timer can be reset manually as many times as desired, but cannot be stopped to avoid ADS initiation, unless Level 1 is restored.

*Fermi 2 and Grand Gulf have this design currently.

After the timer has timed out, the ADS initiation logic confirms that at least one low pressure ECCS pump is operating (to provide assurance that makeup water is available for injection to the RPV once it is depressurized). Once all signals have been received, reactor depressurization is initiated by opening all the ADS designated safety relief valves.

(2) Perry and Nine Mile Point 2

The logic for these plants does not use the high drywell pressure trip signal for the ADS timer and includes a manual inhibit switch which allows the operator to inhibit ADS initiation. This version permits automatic depressurization in the event of a steam line break outside the drywell or for transient events which cause low water Level 1 trip without producing a high drywell pressure trip. There is not a separate drywell pressure bypass timer provided.

The ADS timer is initiated when the Level 1 trip signal is confirmed by a concurrent Level 3 trip signal. The timer automatically stops and resets if the water level is restored above Level 1. Manual reset returns the timer to the initial value but does not stop it. After the timer has timed out, the logic confirms that at least one low pressure Emergency Core Cooling System (ECCS) pump is operating (to provide assurance that makeup water is available for injection to the RPV once it is depressurized) and if the manual inhibit switch has not been activated, reactor depressurization is initiated by opening all the ADS designated safety relief valves. Use of the manual inhibit switch is controlled by plant emergency procedures.

(3) River Bend, Clinton, Grand Gulf*, Fermi 2*, Hope Creek and Limerick

The logic for these plants incorporates a drywell pressure bypass timer and a manual inhibit switch. This permits automatic actuation of ADS for steam line breaks outside the drywell and does not affect the original high drywell pressure - low water level initiation sequence for pipe breaks inside the drywell.

Low water Level 1 trip signal initiates the bypass timer to allow additional time for high drywell pressure trip signal. When this timer times out, the ADS timer starts if a low water Level 3 trip signal is also present, even if high drywell pressure trip has not occurred. This ADS timer automatically stops and resets if the water level is restored above Level 1. Manual reset returns both timers to their initial values.

After this ADS timer has timed out, the logic requires confirmation that sufficient low pressure ECCS pump(s) are operating (to provide assurance that makeup water is available for injection to the RPV once it is depressurized) and if the manual inhibit switch is not activated, reactor depressurization is initiated by opening all the ADS designated safety relief valves. Use of the manual inhibit switch is controlled by plant emergency procedures.

3.9.3 Setpoint Calculations

The instrument setpoint calculations follow the methodology of Section 1. The system engineer assigns values to the instrument channel accuracy, calibration, and drift, based on knowledge of the system requirements and instrumentation capabilities. These values are used in calculating the Allowable Value (AV) and the Nominal Trip Setpoint from the upper

*Fermi 2 and Grand Gulf have committed to the NRC to revise their logic to this option at a later date.

Analytical Limit (AL), per the procedure described in Section 1. Margin to the lower analytical limit is then assured by calculations from the NTSP. The probability of Licensee Event Report (LER) avoidance is also calculated using the method detailed in Section 1.

3.9.4 Analysis

The Design Basis Event (DBE) for the ADS timer setpoint is a small liquid line break on the recirculation suction line. This DBE is analyzed as part of the FSAR Loss of Coolant Accident (LOCA) analysis using the upper limit of 120 seconds for the ADS time delay. This timer setting keeps the small break from becoming the Design Basis Accident (DBA). The results analyzed using SAFE code (NRC approved licensing evaluation model for FSAR analysis) are summarized in Table 3.9-1 for a typical plant, and demonstrate conformance to the acceptance criteria of 10CFR 50.46.

For a pipe break inside the drywell, the high drywell pressure trip occurs before the low RPV water level trip. Since the original ADS initiation logic requires both trip signals, the ADS logic modification has no effect on ADS performance for events which pressurize the drywell.

The DBE for the drywell pressure bypass timer setpoint is a postulated guillotine break of a main steam line outside the containment (isolation event). Addition of the timer bypassing the high drywell pressure trip results in ADS actuation occurring no more than 10 minutes after low RPV water reactor level trip. This DBE was analyzed based on a design basis FSAR calculation. This calculation assesses the maximum potential adverse impact of the ADS actuation logic alternatives of either eliminating the high drywell pressure trip or installing an additional timer bypassing high drywell pressure trip. The maximum allowable bypass timer setting is determined by keeping the steam line break outside the containment from becoming the limiting break. The results of this analyses are summarized in Table 3.9-1 for a typical plant.

Table 3.9-1

ADS AND ADS BYPASS TIMER

ADS BYPASS TIMER		ADS TIMER	
UPPER	LOWER	UPPER	LOWER

For Fermi 2, Hope Creek and Limerick, analyses are performed to show that RPV water level is restored above Level 1 within 300 seconds after it drops below Level 1 during Anticipated Transient Without Scram (ATWS) events. Grand Gulf is analyzed to show that the level is restored above Level 1 in 606 seconds. River Bend and Clinton have not purchased ATWS function from General Electric and, therefore, analyses for the lower limit on these plants are not made. For plants without the bypass timer (Perry and NMP2), operator action is required to avoid ADS actuation during ATWS events.

3.9.5 Assumptions and Uncertainties

The following assumptions are made in the determination of the setpoint:

(1)

(2)

(3)

(4)

(5)

(6)

3.10 MAIN STEAM ISOLATION VALVE CLOSURE POSITION SWITCH

3.10.1 Purpose

The purpose of the Main Steam Isolation Valve (MSIV) closure position switch trip is to initiate reactor scram whenever a sufficient number of MSIVs are closed. Reactor pressure rises when the valves close, causing an increase in reactor power. Position sensors mounted on the valves provide timely signals used to initiate scram to limit the resulting pressure rise and, hence, to reduce the severity of the transient.

Various steamline and nuclear system malfunctions or operator actions can initiate an MSIV closure event. Examples are low steamline pressure, high steamline flow, high steamline radiation, low reactor vessel water level, and manual action.

3.10.2 Trip Logic Description

Each of the four steamlines have two isolation valves. For all plants except Clinton, each valve is equipped with two position switches or two contacts on a single switch. The relay trip logic is arranged such that a scram signal results whenever either inboard valves or outboard valves of three or more steamlines close to positions below the trip setpoint.

This logic arrangement allows test functions which include isolation of one steamline and isolation valve closure to positions below the nominal trip setpoint for another steamline without causing a Reactor Protection System (RPS) trip (to scram the reactor) from the MSIV closure position switch trip. To assure that an RPS trip does not result from some other setpoint, the reactor power is reduced for the test functions to limit reactor pressure and steam generation which may cause RPS trip when high.

Clinton has a single position switch with a single contact for each valve. The solid-state logic is arranged as two-out-of-four (i.e., a scram signal results when two or more steamlines are isolated by inboard and/or outboard valves). For Clinton, test functions to permit isolation of one steamline and closure of one isolation valve in any one of the other steamlines is obtained by bypassing one of these channels.

3.10.3 Setpoint Calculations

The instrument setpoint calculations follow the methodology of Section 1. The system engineer assigns values to the instrument channel accuracy, calibration accuracy and drift, based on knowledge of system requirements and instrumentation capabilities, supplemented by engineering judgment. Historically, a 90% (of full open position) analytical limit has been chosen to initiate reactor scram. However, the ultimate limit depends on how high the switch contacts can be set. On several plants, the position switches cannot be set at a 94% nominal trip setpoint (which corresponds to an analytic limit of 90%) because of mechanical constraints on the Main Steam Isolation Valves. Therefore, all plants except Nine Mile Point 2 (which supplied their own MSIVs and position switches) have been evaluated using an analytical limit of 85% to allow a lower setting of nominal trip setpoints.

The Allowable Value (AV) and the Nominal Trip Setpoint (NTSP) are subsequently established following the procedure described in Section 1. The probability of Licensee Event Report avoidance is then calculated using the methods of Section 1.

3.10.4 Analysis

The Design Basis Event (DBE) for the MSIV closure position trip is closure of all MSIVs with position trip scram. The ODYN code is used to simulate this transient for all plants except Clinton and Fermi 2, which used the REDY code (ODYN and REDY are NRC approved licensing evaluation models used in FSAR analyses). The applicability of the River Bend FSAR ODYN results to Clinton for pressurization transients is justified in the Clinton FSAR (Section 15.2). Therefore, the River Bend MSIV closure results are applied to Clinton. The transient was conservatively initiated from a full power condition of 105% Nuclear Boiler Rated (NBR) steam flow for all plants except Fermi 2, which was initiated from 102% NBR power. The analyses utilize the most conservative MSIV closure time of 3 seconds, compared to a nominal range of 3 to 5 seconds.

A scram delay (sensor plus logic) time of 0.06 seconds was included in the analyses.

Inputs to these analyses involve protection system settings, system capacities and system response characteristics. In all cases, conservative values are used in the analyses, following licensing basis procedures.

The results of the analysis are summarized in Table 3.10-1 for a typical plant.

3.10.5 Assumptions and Uncertainties

Assumptions or uncertainties which are not identified or quantified in the Setpoint Calculations or Analysis sections are addressed below:

(1)

(2)

(3)

(4)

Table 3.10-1

MSIV POSITION SWITCH

*The reactor vessel bottom pressure corresponding to ASME moderate frequency event limits.

(5)

(6)

3.11 MAIN STEAM LINE RADIATION MONITOR

3.11.1 Purpose

The purpose of the Main Steam Line Radiation Monitors (MSLRM) is to detect events, such as a Control Rod Drop Accident, which damage the reactor core and result in a gross release of fission products from the core.

The MSLRMs provide signals to the Reactor Protection System (RPS) to initiate a reactor scram, and to the Nuclear Steam Supply Shutoff (NSSS) System for Main Steam Isolation Valve (MSIV) closure and mechanical vacuum pump shutdown and isolation (if used by the Architect/Engineer). The monitors thus serve to mitigate both further core damage and potential radioactivity releases to the environment.

The MSLRMs are located in the vicinity of the Main Steam Lines, downstream of the Main Steam Isolation Valves. The detectors operate in the presence of the normally high level of Nitrogen-16 radiation activity in the steam lines.

3.11.2 Trip Logic Description

There are a total of four MSLRMs provided, one each for RPS channels A_1, B_1, A_2, B_2 for BWR/4 and 5 plants and A,B,C,D for BWR/6 plants. The trip logic for reactor scram and isolation is arranged in one-out-of-two-twice logic. For BWR/4 and BWR/5 plants one trip signal from A_1 or A_2 and another trip signal from B_1 and B_2 provide permissives for the trip functions and for BWR/6 plants one signal from channels A or C and one signal from B or D provide the permissive.

3.11.3 Setpoint Calculations

The trip point is currently set, per Nuclear Regulatory Commission guidance, at three times the normal full power radiation dose rate at the detectors. The difference between the allowable value (3.6 times full power background) and the trip setpoint (3 times full power background) allows for channel drift. The assignment of error allowances is described in Table 3.11-1.

Because no credit is taken for the MSLRM, a safety limit and analytical limit are not associated with the setpoint.

3.11.4 Analysis

Credit for the actions of this monitor is not taken in the conservative accident analysis of the Final Safety Analysis Report (FSAR).

3.11.5 Assumptions and Uncertainties

The following assumptions are used in the setpoint determination:

(1)

(2)

(3)

(4)

(5)

(6)

Table 3.11-1

MAIN STEAM LINE RADIATION MONITOR

Analytical Limit	N/A*
Primary Element Accuracy	0%
Process Measurement Accuracy	0%
Allowable Value	3.6 x Background****
Nominal Trip Setpoint	3.0 x Background****
Safety Limit	N/A*
Bounding Value	N/A*
Modelling Bias	N/A*
Margin	N/A*

*No credit for the main steam line radiation monitor (MSLRM) is taken in FSAR Chapter 15 accident analyses for which they may be propagated.

****The setpoint and allowable value for the MSLRM are established by the NRC. The current values are multiples (3x and 3.6X respectively) of full power radiation background in the steam tunnel and are set in the field.

3.12 MAIN STEAM LINE LOW PRESSURE

3.12.1 Purpose

Main Steam Isolation Valve (MSIV) closure on low steam line pressure is provided to protect the reactor system against uncontrolled depressurization. Protection is provided primarily against a pressure regulator malfunction which results in the turbine control and/or bypass valves opening. The Main Steam Line (MSL) low pressure trip setpoint is specified to limit the duration and severity of the depressurization so that vessel thermal stresses (resulting from vessel cooldown rate) remain below the appropriate safety limit and inventory loss is limited to prevent uncovering fuel.

3.12.2 Trip Logic Description

Each of the four steam lines is furnished with pressure instrumentation to measure steam line pressure upstream of the turbine stop valve. Logic is provided to close the MSIVs when the reactor mode switch is in the "RUN" position and the main steam line pressure drops below the specified setpoint.

Pressure instrumentation for each of the four steam lines provides a signal to a trip unit, one for each channel A,B,C and D. The trip unit signals, in turn, feed into the logic circuit for closure of the MSIVs.

All plants except Clinton use relay logic for MSIV closure arranged in one-out-of-two-twice logic, for input signals from channels A,B,C and D. For this logic arrangement, all the MSIVs are tripped to close when either channel A or C, and channel B or D provide low pressure trip signals. This logic is bypassed when the reactor mode switch is not in "RUN" position to permit startup of the plant.

The Clinton plant uses solid-state logic for MSIV closure arranged in two-out-of-four logic. For this logic arrangement, all the MSIVs are closed when two or more of the four channels provide low pressure trip signals. This logic is bypassed when the mode switch is not in "RUN" mode to permit startup of the plant.

3.12.3 Setpoint Calculations

The instrument setpoint calculations follow the methodology of Section 1. Initial data include the Analytical Limit (AL) and Operational Limit (OL) specified on a historical basis, supplemented with transient performance analysis. The AL is selected so that for the Design Basis Event (DBE) corresponding to pressure regulator failure open event, vessel temperature change rate is less than 100°F/hr (Reference 6) and reactor water level does not drop below Level 1. The OL is selected so that MSL low pressure trip is avoided during operational maneuvers and expected transients, including turbine generator trips. The system engineer assigns values to the instrument channel accuracy, calibration accuracy and drift, based on knowledge of system requirements and instrumentation capabilities. Instrument accuracy and drift are then confirmed using the methods in Section 2. These values are used in calculating the Allowable Value (AV) and the Nominal Trip Setpoint (NTSP), from the AL following the procedure in Section 1. An example is presented in Table 3.12-1. The probabilities of Licensee Event Report (LER) avoidance and spurious trip avoidance are also calculated using the method described in Section 1.

3.12.4 Analysis

The DBE for MSL low pressure trip is the pressure regulator failure open event. The REDY (NRC approved licensing evaluation model used in the FSAR analysis) code was used to simulate this transient. The transient was initiated from full power conditions of 105% Nuclear Boiler Rated (NBR) steam flow for all plants except Fermi 2, which was initiated from 102% NBR power. The analyses simulated a pressure regulator failure with 130% steam

Table 3.12-1

MAIN STEAM LOW PRESSURE

*Maximum normal primary system temperature change rate as allowed by the ASME.

flow as a worst case, compared with a 115% normal maximum limit. Sensor and logic delays for trip functions were included in the simulation.

3.12.5 Assumptions and Uncertainties

The following assumptions are made in the setpoint determination:

(1)

(2)

(3)

(4)

(5)

(6)

3.13 MAIN STEAM LINE HIGH FLOW

3.13.1 Purpose

The flow in each of the four main steam lines is monitored by four differential pressure transmitters, which measure the pressure drop across a venturi type flow element located between the reactor pressure vessel and the inboard Main Steam Isolation Valves (MSIVs).

The flow element serves a dual purpose. It serves as the primary element for the measurement of flow, and is also specifically designed to limit the maximum flow in one steam line, resulting from a postulated guillotine break of a main steam line, to a rate of flow 200% (170% for BWR/6) or less of rated mass flow. This choked flow rate is the Design Safety Limit.

3.13.2 Trip Logic Description

Whenever the preset trip setpoint is exceeded, the flow transmitters and their associated trip units cause the isolation logic to close the MSIVs in all four main steam lines. There are a total of 16 high flow trip units, one each for channels A, B, C and D for each of the four steam lines. For relay logic plants (all plants except Clinton), the isolation logic for the main steam lines is arranged in one-out-of-two twice logic. For Clinton, the logic is two-out-of-four. Since high flow signals from any one steam line will activate the isolation logic for all four steam lines, any one of eight input signals from channels A and C, together with any one of eight input signals from channels B and D, will close all eight isolation valves, thus isolating all four main steam lines.

3.13.3 Setpoint Calculations

The instrument setpoint calculations follow the methodology described Section 1. Plant-unique flow element calibration data are used to convert 140% flow to differential pressure units (psid). This instrument channel does not utilize square-root extraction, therefore all setpoint calculations are done in psid units.

The system engineer assigns values to the instrument channel accuracy, calibration, and drift based on knowledge of system requirements and instrumentation capabilities. The values for accuracy and drift are then confirmed using the methods outlined in Section 2. In addition, calculations are performed to determine the Process Measurement Accuracy (PMA) and Primary Element Accuracy (PEA).

The Allowable Value (AV) and the Nominal Trip Setpoint (NTSP) are then obtained by making allowances for instrument accuracy, calibration, drift, PMA and PEA as appropriate. An example is presented in Table 3.13-1. The probabilities of Licensee Event Report (LER) avoidance and spurious trip avoidance are then calculated, using the methods described in Section 1. Initial data includes the following:

Analytical Limit: The Analytical Limit is specified at 140% of rated mass flow, to provide a margin above the operational limit.

Operational Limit: The Operational Limit is specified at 127% of rated flow based on operating experience, as a value that will avoid isolation trips during any normal operating transients that cause unbalanced flows in the main steam lines. Examples include closure of one main steam line for valve testing and inadverdent opening of one bypass valve.

3.13.4 Analysis

In the analysis for the postulated guillotine break of a main steam line outside the containment performed using the SAFE code (NRC approved licensing evaluation model), it is assumed that the steam flow increases instantaneously from a conservative full power steam flow of 105% of rated

Table 3.13-1

MAIN STEAM HIGH FLOW

*The models used by General Electric for LOCA analysis have a known conservative modelling bias of several hundred degrees.

**Actual margin is this value plus several hundred degrees F modelling bias.

to the Design Safety Limit (170% BWR/6 and 200% for BWR 4/5). The closure signals are applied to the Main Steam Isolation Valves one half second later.

The Design Safety Limit provides margin to ensure that the licensing safety limits (postulated radiological consequences) are not exceeded. The offsite radiological doses as a consequence of the event are limited to a small fraction of 10CFR100 limits.

3.13.5 Assumptions and Uncertainties

The following assumptions are used in the setpoint determination:

(1)

(2)

(3)

(4)

(5)

(6)

3.14 HIGH DRYWELL PRESSURE

3.14.1 Purpose

The drywell is the enclosure designed to withstand the expected peak transient pressure that could result from the worst case postulated Loss of Coolant Accident (LOCA) and is one of the barriers that prevents radioactive release to the environment. During normal reactor operation, the drywell in plants with Mark I or Mark II containments may have nitrogen atmosphere, and the drywells in plants with Mark III designs contain air.

The drywell pressure is maintained close to atmospheric pressure when the reactor is operating. An increase in the drywell pressure could indicate a LOCA and the high drywell pressure trip is a signal used to identify such a condition. The trip signal initiates reactor scram and contributes to initiation of the Automatic Depressurization System (ADS) for all plants except Perry and Nine Mile Point 2. High drywell also may initiate the appropriate Emergency Core Cooling Systems (ECCS) such as High Pressure Core Spray*/High Pressure Coolant Injection, Core Spray*/Low Pressure Core Spray, and Low Pressure Coolant Injection function of the Residual Heat Removal (RHR) system. High drywell pressure also provides a permissive for containment spray initiation (for Perry, Clinton and Grand Gulf) and contributes to isolation signals for all plants.

3.14.2 Trip Logic Description

Transmitters monitor pressure at four locations in the drywell, and are located outside the drywell for Mark I and Mark II containments and connect to the drywell atmosphere via instrument lines through drywell penetrations.

On plants with Mark I or Mark II containments, the transmitters are located in the reactor building, while on plants with Mark III containments, they are located inside the primary containment (but outside the drywell).

*The HPCI and CS systems are on BWR/4 plants. BWR/5 and BWR/6 plants have HPCS and LPCS, respectively, as the equivalent systems.

The logic necessary to initiate reactor scram requires two trip signals designated as one-out-of-two-twice, except for Clinton which has two-out-of-four logic. The ECCS systems have two or four instruments per division which are combined with other transmitters (such as low water level) that result in the systems initiation.

3.14.3 Setpoint Calculations

The instrument setpoint calculations follow the methodology in Section 1. The system engineer assigns values to instrument channel accuracy, calibration and drift based on knowledge of the system requirements and instrumentation capabilities. The accuracy and drift are then confirmed using the methods in Section 2. The Allowable Value (AV) and Nominal Trip Setpoint (NTSP) are established per the methodology described by Section 1. An example of a typical plant is presented in Table 3.14-1. The calculations for Licensee Event Report (LER) are also performed using the methodology in Section 1.

Perry, Clinton and Grand Gulf use absolute pressure devices referenced to a regional average barometric pressure. Additional consideration is given for these plants to the margin available to minimize spurious trips under expected high barometric pressure and assuring the analytical basis is not violated when low barometric pressure is encountered.

3.14.4 Analysis

General Electric has historically used 2 psig as an analytical limit for high drywell pressure trip (2.5 psig for Grand Gulf). This is conservative and provides assurance that the bases for the accident analysis presented in Chapter 6 of the FSAR are not violated. The bounding event is a small break LOCA. The ECCS analysis assumes that high drywell pressure trip has been received prior to reactor water Level 1 trip signal, such that the Auto Depressurization System (ADS) may be initiated. Drywell pressurization calculations performed by GE show that for any break size area above 2 square inches, the high drywell signal will occur before Level 1 is reached.

Table 3.14-1

HIGH DRYWELL PRESSURE

*The models used by General Electric for LOCA analysis have a known conservative modelling bias of several hundred degrees.
**Actual margin is the value plus several hundred degrees F modelling bias.

3.14.5 Assumptions and Uncertainties

The following assumptions are made in the setpoint determination:

(1)

(2)

(3)

(4)

(5)

(6)

3.15 HIGH CONTAINMENT PRESSURE *

3.15.1 Purpose

The high containment pressure instruments provide a signal for initiation of the containment spray mode of the Residual Heat Removal (RHR) System. The RHR containment spray mode is required on some plants with Mark III containments to ensure condensation of steam which leaks into the containment (wetwell) from inside the drywell without passing through the suppression pool.

After a Loss of Coolant Accident (LOCA), the RHR system is devoted to the Low Pressure Coolant Injection (LPCI) mode. Automatic switchover to the containment spray mode is inhibited by timers to allow for reactor water level recovery. After an initial time period (approximately 10 minutes), if a high containment pressure exists and a high drywell pressure signal also exists, automatic transfer of the RHR System loops A and B from the LPCI mode to the containment spray mode is initiated. Loop A transfer is initiated first, Loop B transfer to the containment spray mode is delayed on some plants to allow time for Loop A to reach rated containment spray. This reduces the possibility that unnecessarily low containment pressures would occur due to an over abundance of containment spray flow that may be associated with simultaneous initiation of both loops. It has been demonstrated by analysis that simultaneous initiation of both spray loops is acceptable (for Clinton and Grand Gulf) and Grand Gulf has deleted the additional 1.5 minute time delay for Loop B initiation.

*This section of the report applies to the following plants only: Perry, Grand Gulf, and Clinton.

3.15.2 Trip Logic Description

Four pressure transmitters are furnished to sense the containment (wetwell) pressure. Two transmitters are provided for RHR loop A and two for loop B. The logic is arranged so that, if either one of the two Loop A containment pressure instruments, as well as the drywell pressure instruments, is reading above their setpoints after the timer has timed out, then RHR loop A will transfer from the LPCI mode to the containment spray mode. After an additional delay (on some plants), RHR loop B will also transfer to the containment spray mode when either one of the loop B containment pressure instruments, as well as the drywell pressure instruments, is reading above their setpoints. For Grand Gulf, both loops will transfer modes after the timer has initially timed out (nominal of 10 minutes).

3.15.3 Setpoint Calculations

The instrument setpoint calculations follow the methodology described in Section 1. The system engineer assigns values to the instrument channel accuracy, calibration and drift selected based on knowledge of the system requirements and instrumentation capabilities. The instrument accuracy and drift are then confirmed using the methods in Section 2. The methodology presented in Section 1 is used to determine the Allowable Value (AV) and Nominal Trip Setpoint (NTSP) based on the Analytical Limit (AL).

The probability of Licensee Event Report (LER) assistance is then calculated using methods described in Section 1. Calculations for spurious trip avoidances probability are not required for this device because there is no significant pressure increases in the containment during normal plant operation.

An example of the allowances made for the setpoint are presented in Table 3.15-1.

Table 3.15-1

HIGH CONTAINMENT PRESSURE

*Modelling bias and margin are inherent in the assumed bypass leakage ($A\sqrt{K}$), which is significantly greater than the normally experienced in the field. The effects of conservative values of $A\sqrt{K}$, in terms of modelling bias and margin have not been quantified.

3.15.4 Analysis

The Analytic Limit (AL) for the high containment pressure setpoint is established such that the containment Mark III design pressure of 15 psig will not be exceeded. Briefly, the AL is determined by the following procedure:

(1) Determine the equivalent drywell-to-wetwell bypass leakage area $(A/\sqrt{K})^*$ which results in the containment reaching the design pressure of 15 psig 13 minutes after the postulated event. Thirteen minutes is the earliest time assumed for spray availability based on 10 minutes for RHR dedication to LPCI plus 3 minutes delay till Loop B is able to achieve full spray flow. Loop A is assumed to have failed.

(2) Calculate the containment pressure history for the assumed value of bypass leakage.

(3) The AL used in determining the setpoint for spray initiation is taken to be a pressure conservatively lower than the calculated containment pressure 10 minutes after the postulated event. The AL has been established by the type of analysis described above as 9 psig. The containment pressure history typically shows that pressure is greater than the AL at 10 minutes for the design basis event with maximum allowable bypass leakage (conservatively greater than 9 psig).

The maximum allowable bypass leakage permitted by plant technical specifications is an order of magnitude smaller than that resulting from the above conservative analysis procedure (using General Electric Computer models). Actual measured bypass leakage is typically considerably less than that permitted by plant technical specifications.

*Where A is area and K is the loss coefficient for the bypass leakage path (i.e., drywell to containment).

3.15.5 Assumptions and Uncertainties

The following assumptions are made in the setpoint determination:

(1)

(2)

(3)

(4)

(5)

(6)

3.16 LPCI/LPCS* INJECTION VALVE INTERLOCKS

3.16.1 Purpose

The Low Pressure Core Injection (LPCI)/Low Pressure Core Spray (LPCS)* Injection Valves are motor operated stop valves which provide "go/no-go" control for injection of coolant to the core from the low pressure Emergency Core Coolant Systems (ECCS). The injection valves also serve as the interface between the high pressure piping of the reactor vessel and the lower pressure piping of the LPCI/LPCS systems. The LPCI/LPCS injection valves open automatically for the Loss-of-Coolant Accident (LOCA) condition. They are also actuated manually by remote manual switch from the control room under operator procedural control for post-LOCA adjustments of core cooling provisions, as well as for testing.

The interlocks which are the subject of this review inhibit the automatic opening of the injection valves when the reactor vessel pressure is above the maximum allowable design pressure of the LPCI/LPCS pump discharge piping system (hereafter called Hi/Lo Pressure Interlock).

The Hi/Lo Pressure Interlocks have been incorporated to provide backup assurance against low pressure coolant system piping failure from overpressure. Protection against overpressure is provided in the basic system design through a check valve which prevents backflow from the higher pressure reactor vessel, and through relief valves in the lower pressure piping sized in accordance with the requirements of the pertinent ASME Code. The interlock provides protection for the event of a "single failure" of the check valve in a non-closed position.

---

*This description applies to BWR/4, 5 and 6 plants. For BWR/4 plants, the proper title is LPCI/Core Spray (CS); for simplicity of discussion, the designation LPCI/LPCS is used throughout this text when reference is to all plants.

3.16.2 Trip Logic Description

Figures 3.16-1 through 3.16-5 present schematic arrangements of interlock logic for the different plants. These are further described below. For clarity of discussion, although this review relates only to the automatic function, the logic related to manual operation is included for all plants both on the figures and in the descriptions.

Clinton (LPCI and LPCS)
Grand Gulf (LPCI and LPCS)
River Bend (LPCI and LPCS)

Separate interlocks inhibit valve operation for the accident condition and for testing. Output signals of pressure switches, which sense reactor steam dome pressure and which are arranged in one-out-of-two twice logic, inhibit the valve from opening automatically from LOCA input signal or manually from the Remote Manual Switch (RMS) when reactor vessel pressure is above the low pressure system maximum allowable design pressure. One logic train provides output signals to both low pressure systems of an electrical division; that is, one set of four transmitters and switches provides output for the injection valves of LPCS and LPCI (A), a second set in the opposite electrical division supplies signals for LPCI (B) and LPCI(C). The output signal from a separate pressure switch (the Clinton design has two redundant switches), which senses pressure downstream of the valve, provides a permissive for manual valve opening for testing when downstream pressure is below the low pressure system maximum allowable design pressure (See Figure 3.16-1).

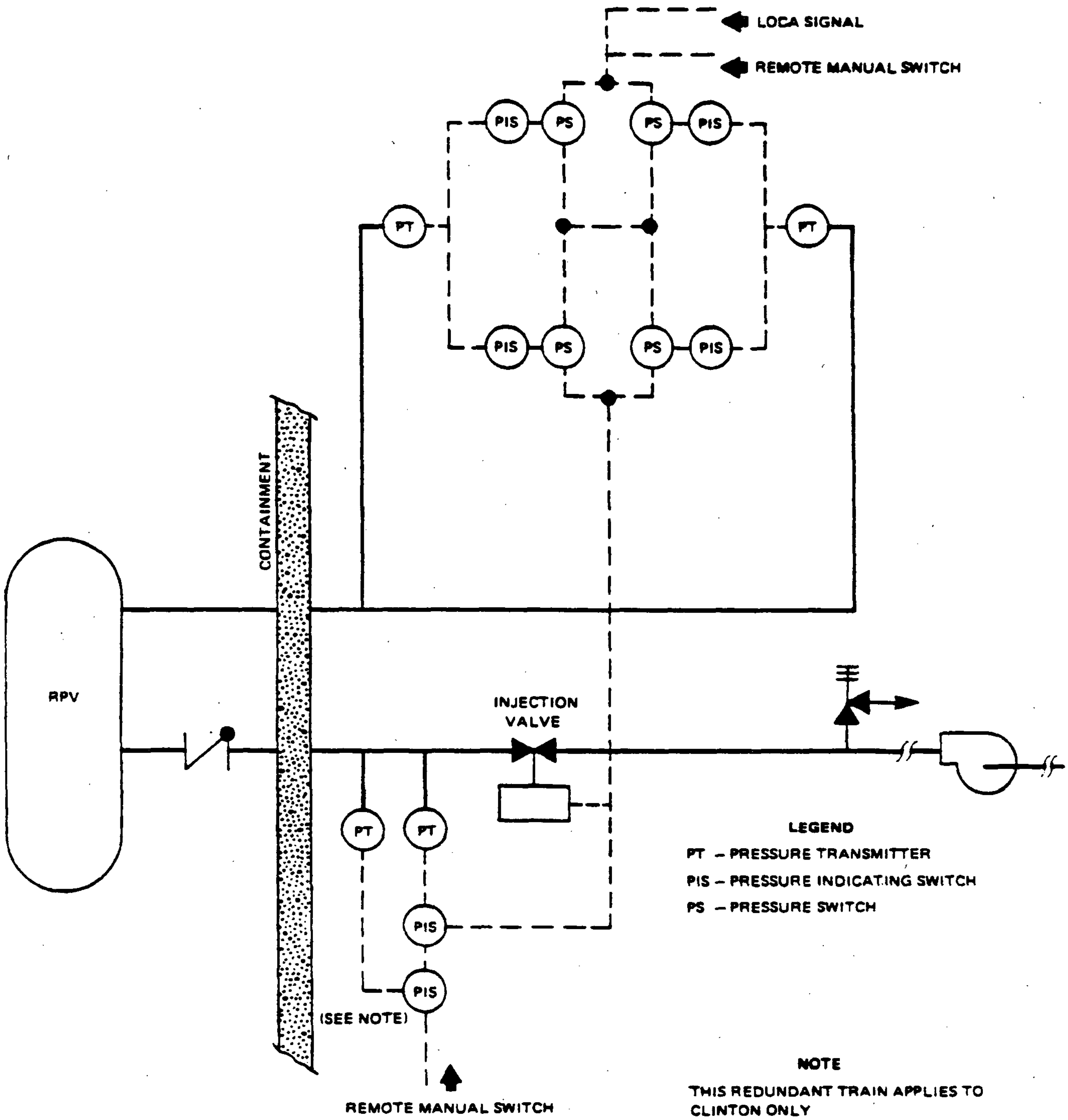


Figure 3.16-1 Simplified Schematic - LPCI/LPCS Injection Valve Interlock (Clinton, Grand Gulf, River Bend)

Perry (LPCI & LPCS)
Hope Creek (LPCI only)

The interlock inhibits automatic and manual valve operation. The output signal from a pressure switch which senses pressure downstream of the valve inhibits valve opening, from either automatic or manual signals, when downstream pressure is above the low pressure system maximum allowable design pressure (Figure 3.16-2).

Nine Mile Point 2 (LPCI & LPCS)

The interlock inhibits automatic and manual valve operation. The output signal of a differential pressure switch, which senses the differential between the reactor dome pressure and the pressure immediately upstream of the valve, inhibits valve opening when this differential is above a value consistent with the design pressure of the applicable low pressure coolant system (Figure 3.16-3).

Limerick (LPCI only)

The interlock inhibits automatic and manual valve operation. The output signal of a differential pressure switch which senses valve differential pressure, inhibits valve opening when the differential pressure is above a value consistent with the LPCI system maximum allowable design pressure (Figure 3.16-4).

Hope Creek (Core Spray only)
Limerick (Core Spray only)
Fermi 2 (Core Spray and LPCI)

The interlock inhibits automatic and manual valve operation for the LOCA condition. Output signals of pressure switches, arranged in one-out-of-two twice logic, inhibit automatic valve opening from a LOCA input signal as well as manual opening from the remote manual switch when reactor vessel steam dome pressure is above that consistent with CS/LPCI piping system maximum allowable design pressure (Figure 3.16-5). A pressure interlock is

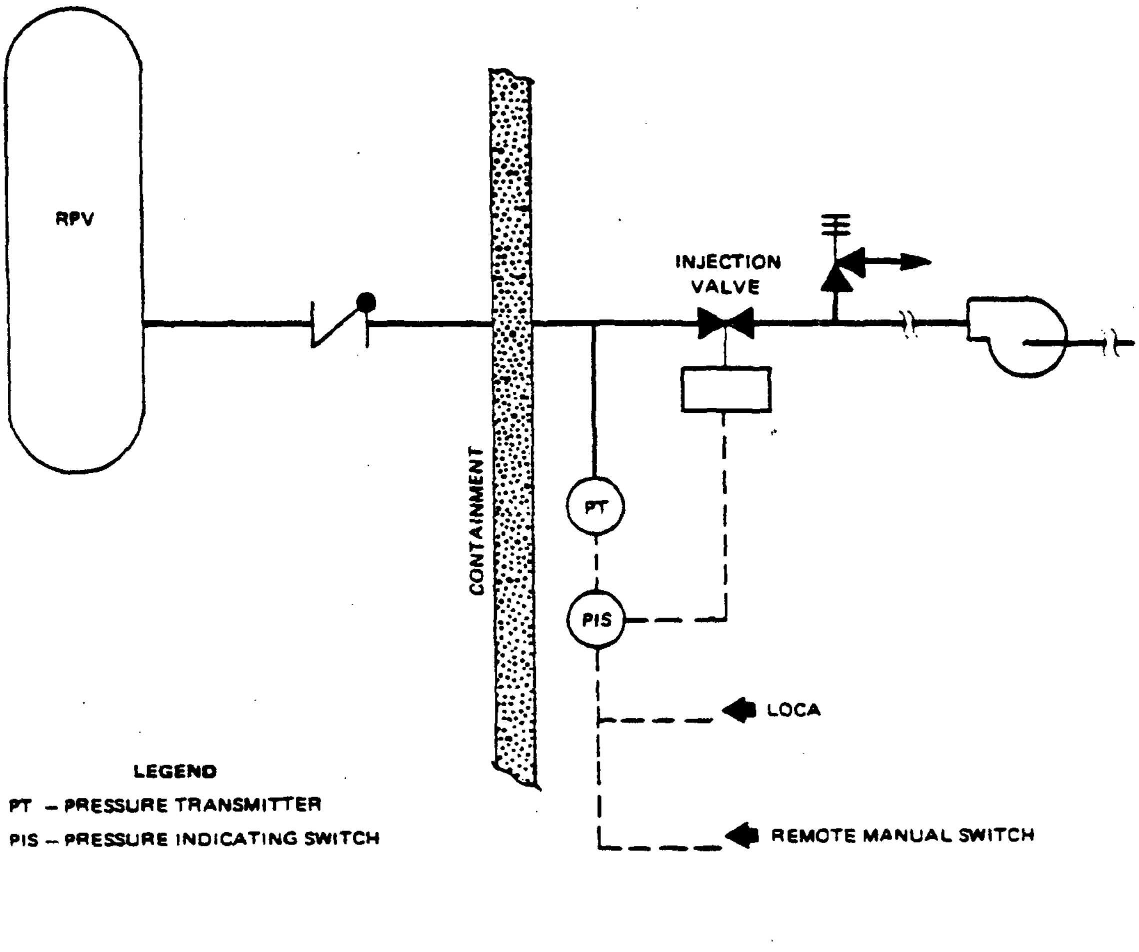


Figure 3.16-2 Simplified Schematic - Injection Valve Interlock (LPCI/LPCS-Perry, LPCI-Hope Creek)

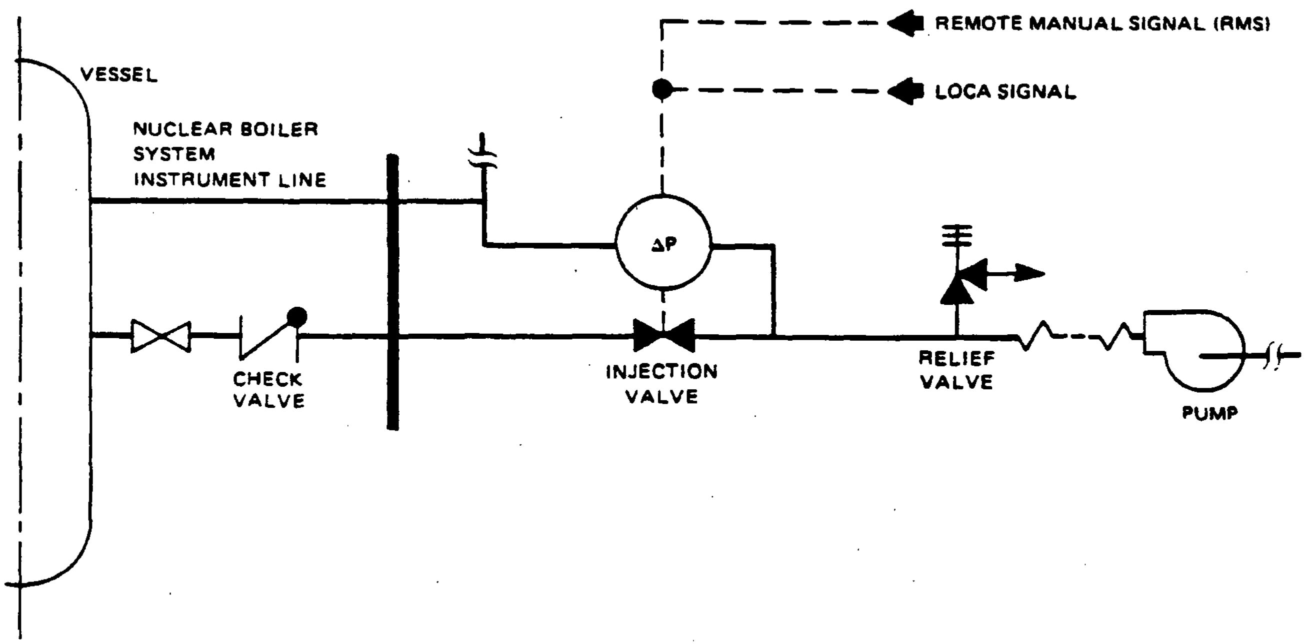


Figure 3.16-3 SIMPLIFIED SCHEMATIC- LPCI/LPCS INJECTIUN VALVE INTERLOCK (NINE MILE POINT 2)

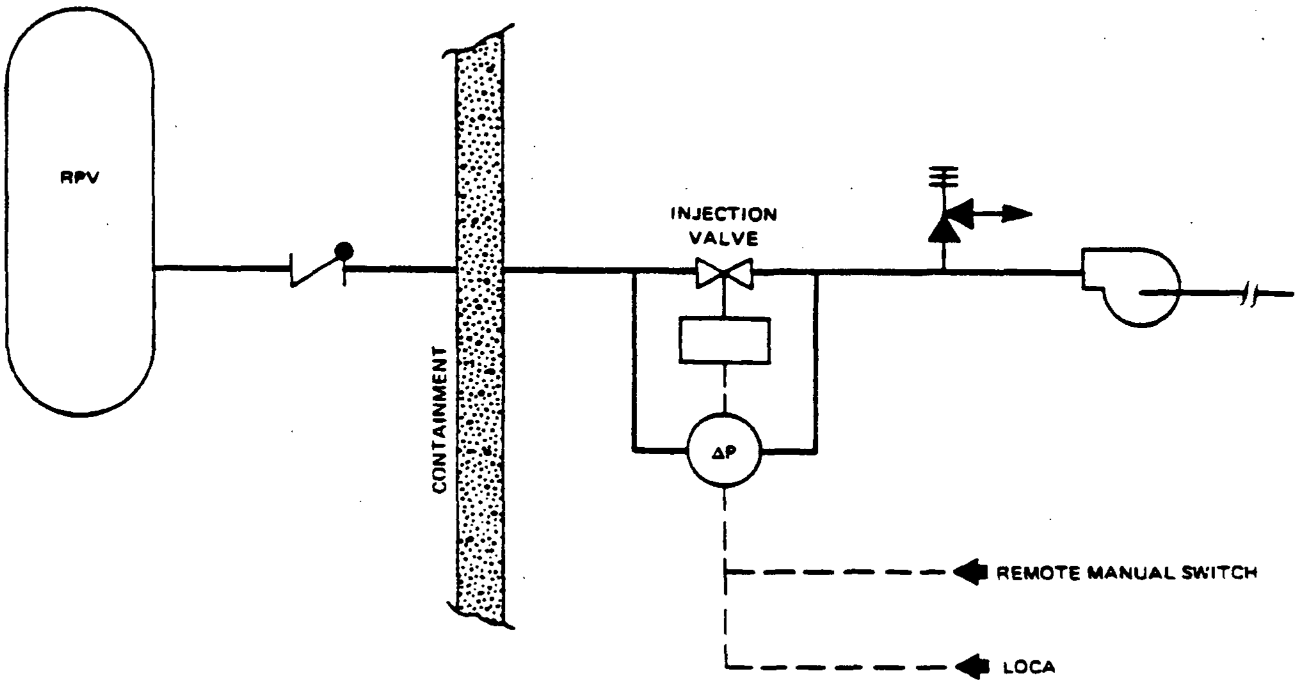


Figure 3.16-4 SIMPLIFIED SCHEMATIC- LPCI INJECTION VALVE INTERLOCK (LIMERICK)

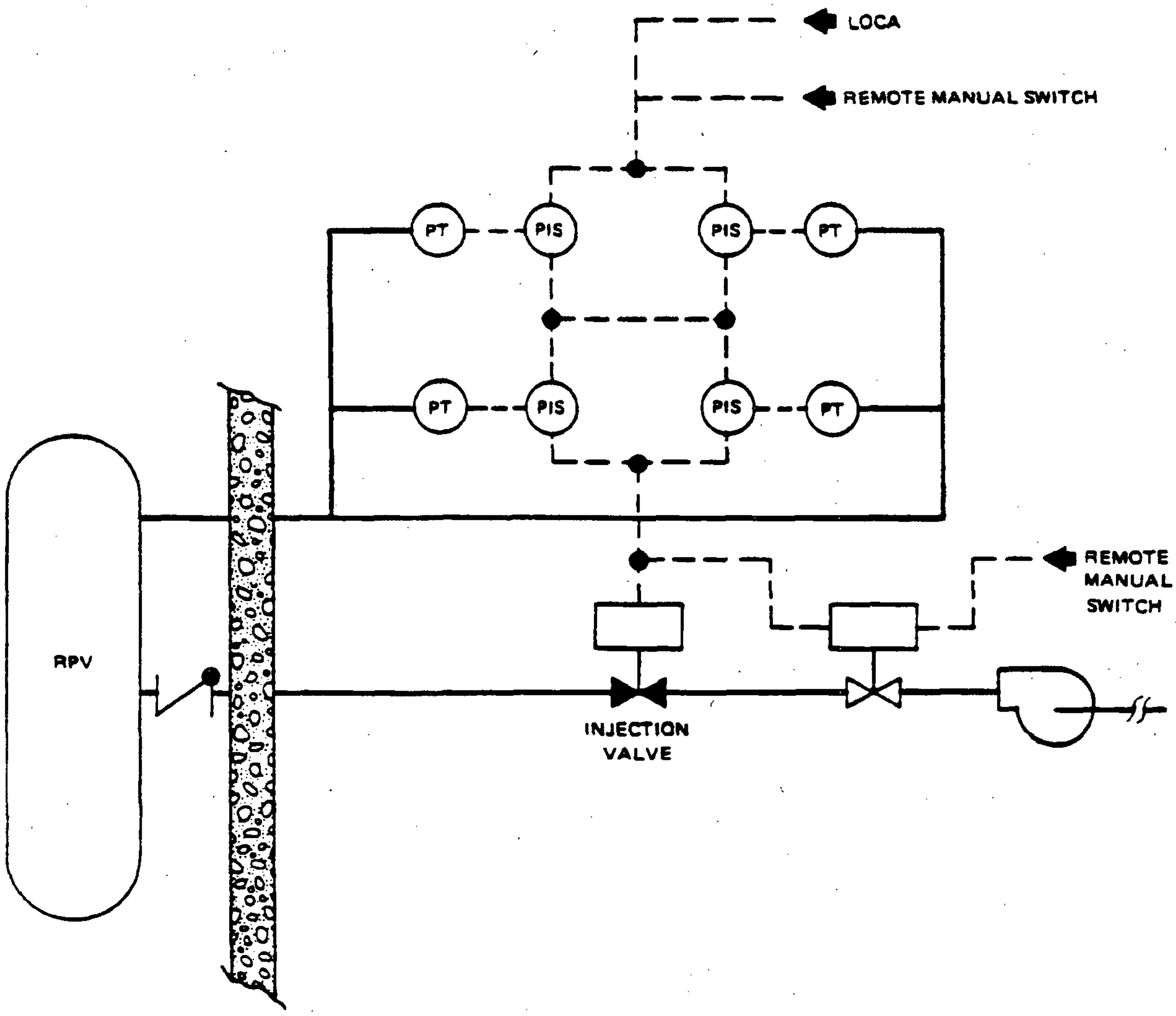


Figure 3.16-5 SIMPLIFIED SCHEMATIC- INJECTION VALVE INTERLOCK
(LPCI/CS- FERMI2, CS- HOPE CREEK, CS- LIMERICK)

not included in the logic for manual valve actuation for testing of these systems. As shown in Figure 3.16-5, an additional valve is provided upstream of the injection valve. The logic includes an interlock such that the injection valve cannot be manually opened for test unless the normally opened upstream valve is first closed.

3.16.3 Setpoint Calculations

The instrument setpoint calculations follow the methodology described in Section 1. The procedure is to: (1) establish an upper pressure limit for valve actuation from the allowable design pressure of the applicable low pressure piping system; (2) from this upper limit and with selected design characteristics for the instrumentation train to derive a nominal trip setpoint for the interlock; and (3) for the selected instrumentation train characteristics, to establish for automatic valve operation the lowest potential reactor pressure to which valve actuation can be inhibited when set at this established setpoint. This lowest potential reactor pressure is then given as input for an analytical assessment of the adequacy of the low pressure injection for core cooling when injection valve actuation is inhibited by an interlock with this setpoint.

The Upper Analytical Limit (UAL) for the Hi/Lo Pressure Interlock is derived through assessment of the allowable design pressures for piping and components that comprise the pressure boundary between the drive pump and the injection valve of the applicable low pressure coolant system. The UAL is selected as the lowest of these allowable pressures after adjustment of this pressure for water head between the elevation of the pipe/component and the elevation at which the pressure is sensed. When applicable, this lowest allowable pressure is converted to a differential pressure across the valve with this same consideration of water heads.

Where deemed applicable, credit is taken for allowance of 110% of design pressure per Subsection NB of ASME Section III on the basis that such overpressure could be expected to have occurrence frequency well below the one percent of plant life which is permitted by the Code.

The system engineer assigns values to the instrument channel accuracy, calibration, and drift based on knowledge of system requirements and instrumentation capabilities. The accuracy and drift are then confirmed using the methods in Section 2. In addition, process measurement accuracy and primary element accuracy are determined as applicable. These values are then used to determine an Upper Allowable Value (UAV) and a Nominal Trip Setpoint (NTSP), corresponding to the Upper Analytical Limit. A Lower Allowable Value (LAV), corresponding Nominal Trip Setpoint are then determined from the Lower Analytical Limit (LAL). Any final NTSP lying between the two nominal trip setpoints may then be utilized. The determination of the last two values is performed only for automatic valve actuation setpoints, not manual permissives.

The probability of Licensee Event Report (LER) avoidance is then calculated using the methods described in Section 1. Spurious trip avoidance calculations are not performed, since trip avoidance is not a concern, as this is an interlock signal and not a trip. Further, the trip points are on the order of 50% of the normal reactor operating pressure and, therefore, spurious trip of the interlock during normal plant operation is not a credible concern.

Setpoint examples from two different plants for LPCI and CS injection valve interlocks are presented in Tables 3.16-1 and 3.16-2.

3.16.4 Analysis

ECCS performance is analyzed for the postulated guillotine break of the reactor recirculation system primary piping to assess the maximum potential adverse impact of adding the injection valve interlock. If this Design Basis Accident (DBA) recirculation suction line break is not the limiting break then a spectrum of large breaks must be analyzed. This is required to determine whether the limiting break size changes as a result of the injection valve interlock. In these analyses it is conservatively assumed that flow through the injection valve is not initiated until the valve is fully opened.

Analytical assessment of Peak Clad Temperature (PCT) for the LOCA condition is performed with the with coolant injection inhibited until reactor pressure is at the calculated LAL and the injection valve is fully open.

3.16.5 Assumptions and Uncertainties

The following assumptions are made in the setpoint determination:

(1)

(2)

(3)

(4)

Table 3.16-1

LPCI INJECTION VALVE INTERLOCK
TYPICAL BWR/6

UPPER	LOWER

*The nominal trip setpoint should be chosen to be equal or between these values.

**The models used by General Electric for LOCA analysis have a known conservative modelling bias of several hundred degrees.

***Actual margin is this value plus several hundred degrees F modelling bias.

Table 3.16-2

CS INJECTION VALVE INTERLOCK
TYPICAL BWR/4 PLANT

UPPER	LOWER

*Reactor dome pressure.

**The nominal trip setpoint should be chosen to be equal or between these values.

***The models used by General Electric for LOCA analysis have a known conservative modelling bias of several hundred degrees.

****Actual margin is the value plus several hundred degrees F modelling bias.

(5)

(6)

3.17 LOW PRESSURE ECCS PUMP DISCHARGE PRESSURE HIGH

3.17.1 Purpose

The purpose of these instruments is to provide a signal to the Automatic Depressurization System (ADS) control logic when the low pressure Emergency Core Cooling System* (ECCS) pump(s) discharge pressure is high, as an indication of pump operating status. These instruments have no direct effect on the low pressure system control logic.

ADS action is required under conditions when reactor pressure is high and reactor vessel water level is not being maintained by high pressure ECCS. The ADS system is used to decrease reactor vessel pressure so that low pressure systems can inject water to maintain vessel water level. Instrumentation on any single LPCI pump or a similar set of LPCS/CS instrumentation is required to provide the ADS initiation permissive in the ADS initiation logic.

The pressure transmitter tap is connected to the low pressure ECCS pump discharge piping downstream of the pumps and upstream of the discharge line check valves. When there are two pumps per ECCS loop, each transmitter monitors a similar point at the discharge of each pump.

This is true for either an automatic or a manual ADS initiation (Fermi 2 does not have manual initiation). Thus, if the emergency condition itself did not result in automatic LPCS/CS or LPCI pump(s) starting, the plant operator must start the pump(s) in at least one low pressure pump loop to obtain the permissive condition for manual ADS initiation.

*BWR/5 and BWR/6 plants have Low Pressure Core Spray (LPCS) system while the BWR/4 plants have the Core Spray (CS) system. All plants have the Low Pressure Coolant Injection (LPCI) mode of Residual Heat Removal (RHR).

3.17.2 Trip Logic Description

Whenever ADS initiation is required, at least one LPCI or LPCS/CS pump loop must be operating to allow the ADS initiation to proceed. ADS function can be provided via either of two separate and redundant divisions (Fermi 2 has both ADS redundant logic channels in one division). Each division of ADS has two separate channels of logic. For one ADS division, each separate channel must be satisfied because the final logic element prior to blowdown is an "and" gate. Thus, the ADS low pressure pump permissive signals must be two-out-of-two once to provide the proper permissive signal.

3.17.3 Setpoint Calculations

The instrument setpoint calculations follow the methodology described in Section 1. The ADS pressure permissive setpoint must be (1) less than pump discharge pressure when the pump is operating in the minimum flow bypass mode and (2) high enough to avoid any condition which results in a discharge pressure permissive when the LPCI and LPCS/CS pumps are aligned for injection and the pumps are not running. These two criteria establish the limiting conditions for the pressure setpoint Upper and Lower Safety Limit (i.e., USL and LSL).

The upper safety limits corresponding to the first condition are 260 psig for LPCI and 350 psig for LPCS/CS, while the lower safety limit corresponding to the second condition are 55 psig for plants with Mark I and II containments and 25 psig for plants with Mark III containments.

The system engineer assigns values to instrument channel accuracy, calibration, and drift based on a knowledge of system requirements and instrumentation capabilities. The accuracy and drift are then confirmed using the methods in Section 2.

Conservative values of 100 psig for LPCI and 110 psig for LPCS/CS are selected as the Lower Analytical Limits (LAL). The Lower Allowable Value (LAV) and Lower Nominal Trip Setpoint are established by adding allowances for instrument accuracy, calibration and drift to the LAL.

The Upper Analytical Limit (UAL) is also conservatively chosen as 180 psig for LPCS/CS and 150 psig for LPCI. The Upper Allowable Values (UAV) and Upper Nominal Trip Setpoint are established by subtracting allowances for instrument accuracy, calibration, and drift from the UAL. Licensee Event Report avoidance is code confirmed for both the upper and lower nominal trip setpoints. The nominal trip setpoint is then chosen to be between the calculated upper and lower Nominal Trip Setpoints. This procedure assures that an ADS permissive signal will be provided when the pumps are operating and ready for injection. An example of a typical plants values are included in Tables 3.17-1 and 3.17-2.

Calculations for spurious trip avoidances probability are not required for this device because there is no significant pressure decrease in the connected piping system during normal plant operation when the systems are aligned for ECCS initiation.

3.17.4 Analysis

Safety analysis is not performed utilizing these setpoints.

3.17.5 Assumptions and Uncertainties

The following assumptions are made in the setpoint determination:

(1)

(2)

Table 3.17-1

LPCI PUMP ADS INTERLOCK

UPPER	LOWER

Table 3.17-2

LPCS PUMP ADS INTERLOCK

	UPPER	LOWER

*The nominal trip setpoint should be chosen to be equal to or between these values.

**The models used by General Electric for LOCA analysis have a known conservative modelling bias of several hundred degrees.

***Actual margin is this value plus several hundred degrees F modelling bias.

(3)

(4)

(5)

(6)

3.18 CONDENSATE STORAGE TANK LEVEL LOW

3.18.1 Purpose

The purpose of the Condensate Storage Tank (CST) level low setpoint is to initiate the automatic transfer of the systems whose pump suction source is the CST source to the suppression pool source when water level in the tank falls below a preset level. The following systems are involved: Reactor Core Injection Coolant (RCIC) and High Pressure Coolant Injection* (HPCI), or High Pressure Core Spray*(HPCS). This setpoint also initiates an alarm in the control room to alert the operator that the CST water inventory is depleted.

This function is required to prevent loss of suction to the RCIC/HPCI/HPCS pumps due to loss of water in the condensate storage tank. Loss of water can occur as a result of large drawdown of the reserve volume or rupture of the non-seismic tank or piping. Automatic switchover to the suppression pool provides an assured suction source and allows for continued operation of the pumps.

A condition of low condensate storage tank level can be received at any time, causing the suppression pool suction valves to open. The setpoint level is established at a minimum level which assures adequate Net Positive Suction Head (NPSH) for pump operation during the transfer process.

3.18.2 Trip Logic Description

When the sensed CST water level falls below the preset trip setpoint, a signal is generated which causes the system logic to automatically open the appropriate systems' suppression pool suction valves. Upon reaching the full-open position, a limit switch on the suppression pool suction valve(s) is activated, which generates a signal causing closure of the suction valves in the line from the CST. This completes the pump suction transfer process.

*BWR/4 plants have HPCI systems while BWR/5 and 6 plants have HPCS systems. All plants have RCIC.

The instrumentation configuration consists of two completely redundant channels contained within a single division. The signal is processed within each channel by a transmitter and trip unit combination. For HPCI/RCIC/HPCS, the suction transfer signal is generated by a one-out-of-two logic (i.e., trip of either channel will signal the suppression pool suction valves to open).

3.18.3 Setpoint Calculation

The instrument setpoint calculations follow the methodology described by Section 1. The system engineer assigns values to instrument channel accuracy, calibration and drift based on knowledge of system requirements and instrumentation capabilities. The accuracy and drift are then confirmed using the methods in Section 2. The probability of Licensee Event Report (LER) avoidance is then calculated using the methods described in Section 1. Spurious trip avoidance calculations are not performed for this setpoint because it is assumed that there is a large margin between normal tank level and low level. An example of a typical plant are presented in Table 3.18-1. Initial data includes the following:

> Analytical limit: The analytical limit is determined as the tank level which will provide sufficient NPSH during the suction transfer to assure proper pump operation. Consideration is given to tank geometry, suction line arrangement and in-line volumes, suppression pool suction valve opening stroke time, and unusable tank volume.

3.18.4 Analysis

There is no safety analysis associated with condensate storage tank low level setpoint.

Table 3.18-1

CONDENSATE STORAGE TANK

	RCIC	HPCS
Primary Element Accuracy	A/E	A/E
Process Measurement Accuracy	A/E	A/E
Safety Limit	N/A**	N/A**
Bounding Value	N/A	N/A
Modelling Bias	A/E	A/E
Margin		

3.18.5 Assumptions and Uncertainties

The following assumptions are made in the setpoint determination:

(1) Primary Element Accuracy: Primary element accuracy is dependent upon the method the Architect/Engineer (A/E) uses to measure the method of CST level.

(2) Process Measurement Accuracy: This is dependent upon the method of measurement the Architect/Engineer (A/E) uses.

(3)

(4)

(5) Modelling Uncertainty: This is dependent upon the model the A/E uses.

(6)

3.18.6 Additional Information

The information contained in documents provided by GE is concerned only with the instrument and instrument loop capabilities. The minimum condensate tank level required to provide adequate pump suction flow is based on the design of the tank and suction piping system. The A/E is responsible for consideration of the effects of process measurement accuracy, response time and modelling uncertainties on the minimum tank level required to permit safe suction transfer.

3.19 ROD BLOCK MONITOR UPSCALE TRIP - BWR 4/5*

3.19.1 Purpose

The Rod Block Monitor (RBM), which is operable above 30% power, provides a signal to permit operator evaluation of the changes in the local relative power level during control rod movement. The RBM is designed to mitigate a Rod Withdrawal Error (RWE) transient by blocking further control rod withdrawal. This blocking action occurs when the RBM signal reaches a predetermined level. RWE analyses are performed for each reload cycle at the 100% power/100% flow (rated) operating condition. The required RBM rod blocking setpoint is determined such that, starting from the operating limit Minimum Critical Power Ratio (MCPR), the safety limit MCPR is not violated. Experience has established that the MCPR determined trip setpoints will assure that the fuel cladding 1% plastic strain threshold (safety limit) is not exceeded. The setpoint is also supported by two lower trip level setpoints. Credit for the presence of these lower level setpoints is taken for certain off-rated operating conditions.

3.19.2 Trip Logic Description

The RBM channel consists of Local Power Range Monitor (LPRM) detectors in the core, cables from the detectors to the control room panels, LPRM/RBM signal conditioning equipment, flow units and trip units in the control room.

LPRM detectors are miniature fission chambers operating in the saturated ion chamber region. These detectors provide ionization currents proportional to the local neutron flux. The current signals of the detectors surrounding a selected control rod (4 to 8 detectors depending on the position of the control rod in the core) are then routed through cables to

* This report is applicable to Nine Mile Point 2, Fermi 2, Limerick, and Hope Creek. BWR/6 plants are not included because they do not have the Rod Block Monitor system; for these plants the Rod Withdrawal Limiter in the Rod Control System performs a similar safety-related functions.

the LPRM signal conditioning equipment. This signal is then passed to the RBM signal conditioning equipment which averages the LPRM inputs. If this average value is not greater than the associated Average Power Range Monitor (APRM) channel signal level, the RBM signal will be automatically amplified to equal that of the APRM by stepping up the RBM gain. This gain will be held until a new rod is selected. Three recirculation flow biased trip levels, which are 8% apart, limit the local power change by allowing the local average neutron flux indications to increase by a controlled amount. A rod block signal will be sent to the Reactor Manual Control System (RMCS) if this change is too large.

3.19.3 Setpoint Calculations

The instrument setpoint calculations used to determine the Nominal Trip Setpoint (NTSP) and the Allowable Value (AV) for rod block monitor up-scale trip follow the methodology described below.

In this study, the Analytical Limit (AL) is confirmed by statistically combining all uncertainty values of this instrument loop and adding these to the Nominal Trip Setpoint (NTSP). The uncertainties include conservative assumptions, such as assuming that the most responsive RBM channel is bypassed and half of the LPRMs in the remaining RBM channel are failed. However, this study also takes credit for the conservative effect of the RBM signal noise relative to this trip setpoint.

All bias and variability values used in the uncertainty terms to confirm the AL are evaluated and justified with the available manufacturer's or field data. There are more details provided in Section 4.5.

(1)

(2)

(3)

(4)

Table 3.19-1 presents and example for a typical plant.

3.19.4 Analysis

The analytical limit for the rod block monitor upscale trip is determined for each reload cycle by analyzing the Rod Withdrawal Error event. The analysis considers both RBM channels to be operating and no LPRMs failed. The analysis does not take credit for the presence of the setpoint clipping capability of the backup rod block trip circuits, which will contribute much less uncertainty than that from the flow unit and flow-biased trip unit. The LPRM/RBM failure effects are then included as the uncertainties of the RBM trip system in determining the setpoint margin.

3.19.5 Assumptions and Uncertainties

The following assumptions are made in the setpoint determination:

(a)

(b)

Table 3.19-1

ROD BLOCK MONITOR

*W is the measured recirculation drive flow.

(c)

(d)

(e)

(f)

3.20 HIGH APRM NEUTRON FLUX

3.20.1 Purpose

The reactor neutron flux is monitored with the Average Power Range Monitors (APRM) of the Neutron Monitoring System (NMS). If neutron flux increases to a preset high value, a trip signal to the Reactor Protection System (RPS) will initiate reactor scram. Reactor scram is initiated to limit maximum reactor power so as to maintain the peak vessel pressure below and the Minimum Critical Power Ratio (MCPR) above the appropriate safety limits.

3.20.2 Trip Logic Description

The RPS trip system consists of four logic channels. For relay plants (all plants except Clinton), each RPS channel receives signals from two APRM channels, averaging neutron flux signals from representative core wide distributions of Local Power Range Monitors (LPRM). The trip logic for scram is one-out-of-two twice (i.e., Channels A or C and Channels B or D for BWR/6 and Channels A_1 or A_2 and B_1 or B_2 for BWR/4 and 5 plants). For Clinton, the only plant utilizing solid-state logic, each RPS channel receives a signal from one APRM channel, and scram logic is based on two-out-of-four trip logic.

Each APRM channel (loop) consists of the LPRM detectors, cables from under the vessel to the control room, LPRM/APRM signal conditioning equipment and a trip unit (with a dc reference signal) in the control room or the auxillary equipment room.

The LPRM detectors are miniature fission chambers operated in the saturated ion chamber region. They provide ionization currents proportional to the local neutron flux. These current signals are then routed through shielded cables to the LPRM signal conditioning equipment. The APRM signal conditioning equipment, in turn, averages the voltage signals from selected LPRM signal conditioning equipment. The APRM voltage output, which is proportional to the average neutron flux in the core or the percent of rated thermal power, is compared with a dc reference setpoint in the APRM trip units, and a trip signal is sent to the RPS logic circuit if the reference setpoint is exceeded.

3.20.3 Setpoint Calculations

The instrument setpoint calculations follow the methodology described in Section 1. Initial data include the Analytical Limit (AL) and Operational Limit (OL) specified on the basis of transient performance analysis. The AL is chosen such that none of the FSAR transient analyses result in violation of the appropriate safety limits, while the OL is chosen such that there is adequate operating margin to provide a reasonable range for maneuvering while avoiding spurious scrams. The Analytical Limit is determined from the events outlined in Table 3.20-1 and the Operational Limit is determined from a turbine load demand step.

The Allowable Value (AV) and the Nominal Trip Setpoint (NTSP) are established following the procedure in Section 1 to account for instrument channel accuracy, calibration, and drift. The procedure for APRM setpoint validation calculations is presented in Section 4.5.

3.20.4 Analysis

The Design Basis Events (DBE) for the high APRM neutron flux scram setpoint are summarized in Table 3.20-1. Both the peak vessel pressure and the Minimum Critical Power Ratio (MCPR) safety limits are considered. For the peak vessel pressure safety limit, the DBE is Main Steam Isolation Valve (MSIV) closure with neutron flux scram. This is a conservative analysis which assumes that the normal scram path associated with MSIV position switches has failed. For the MCPR safety limit, the DBE is the Fast Recirculation Flow Increase (FRFI) event (one loop) except for Grand Gulf and Limerick. For Grand Gulf, the appropriate DBE is Pressure/Turbine Control System Failure, PTCSF (turbine control valves close at 200%/sec and bypass valves open), because of its unique turbine control system design. For Limerick, the appropriate DBE is Loss of Feedwater Heating (LFWH) in

Table 3.20-1

DESIGN BASIS EVENTS FOR HIGH APRM NEUTRON FLUX SETPOINT

Safety Limit	Plants	Design Basis Event
Peak Vessel Pressure	All	MSIV Closure with Neutron Flux Scram (Position Switch Scram Failure)
MCPR	Perry Clinton River Bend Nine Mile 2 Fermi 2 Hope Creek	Fast Recirculation Flow Increase
	Grand Gulf	Pressure/Turbine Control System Failure (Turbine Control valves closed and bypass valves open)
	Limerick	Loss of Feedwater Heating (manual control)

the manual control mode because there is no Simulated Thermal Power Monitor with a corresponding scram setpoint, and the point model analysis in the Limerick FSAR conservatively shows the event reaching the high APRM flux scram setpoint.

The MSIV closure and PTCSF events are analyzed with the REDY computer code for Clinton and ODYN code for the other plants. The LFWH and FRFI events are analyzed with REDY. REDY and ODYN are NRC approved licensing evaluation models used in the FSAR analysis. The applicability of the River Bend FSAR results to Clinton for pressurization transients is justified in the Clinton FSAR (FSAR Section 15.2). Therefore, the MSIV closure results are applied to Clinton. The MSIV closure, PTCSF and LFWH events are initiated from full power conditions of 105% Nuclear Boiler Rated (NBR) steam flow for all plants except Fermi 2, which was initiated from 102% NBR power. The FRFI event is initiated from the minimum recirculation pump speed limit condition for BWR/4 plants and from the minimum recirculation valve position but maximum pump speed for the BWR/5 and BWR/6 plants. A scram delay (sensor plus logic) time of 0.09 sec is also simulated.

The improved SCAT and ISCOR codes (NRC approved licensing evaluation models used in FSAR analysis) are used to determine the MCPR limit and demonstrate adequate margin to the Safety Limit MCPR.

The results of the analysis are summarized in Table 3.20-2 for a typical plant.

3.20.5 Assumptions and Uncertainties

The following assumptions are made in the setpoint determination:

(1)

(2)

Table 3.20-2

HIGH APRM NEUTRON FLUX

*The reactor vessel bottom pressure corresponding to ASME moderate frequency event limits.

(3)

(4)

(5)

(6)

3.21 HIGH SIMULATED THERMAL POWER TRIP*

3.21.1 Purpose

The Simulated Thermal Power (STP) trip signal is part of the Neutron Monitoring System (NMS). The trip signal is used by the Reactor Protection System (RPS) to scram the reactor to limit maximum reactor power so as to maintain the Minimum Critical Power Ratio (MCPR) above the appropriate safety limit for events such as Loss of Feedwater Heating. The STP setpoint is flow biased so that the scram setpoint is varied with the total recirculation flow rate. The STP signal is derived by processing the Average Power Range Monitor (APRM) neutron flux signal through a filtering network with a time constant which is representative of reactor fuel thermal dynamics. This signal closely approximates the average thermal power during transient and steady-state conditions and thereby makes the Neutron Monitoring System less susceptible to flux spikes under the fixed neutron flux limit (typical allowable value of 120%). The STP trip is designed to make operating BWR plants less susceptible to scrams caused by spurious momentary neutron flux spikes.

3.21.2 Trip Logic Description

The Neutron Monitoring System consists of two major subsystems: (1) APRM and (2) Recirculating Flow Monitoring.

The APRM subsystem consists of four channels, each receiving inputs from incore Local Power Range Monitors (LPRMs). Each APRM channel averages (electrically) the inputs from its assigned LPRMs and provides an output signal proportional to the average of the LPRM flux signals.

The LPRM assignments to APRM channels ensure that each APRM channel receives local neutron flux signals from all four axial locations in the

*Not applicable to Limerick.

core and from LPRMs in a representative radial distribution. Each APRM channel will produce a signal proportional to the average neutron flux of the whole reactor core.

The APRM signal is processed through a thermal power simulator circuit, incorporating a typical time constant of six seconds, to produce an STP signal.

The Recirculating Flow Monitoring subsystem provides APRM system trip units with a signal proportional to total recirculation driving flow. Total recirculation flow consists of the sum of the reactor recirculation pump flow in both recirculation loops). The trip circuits which cause scram trips to the RPS receive the total recirculation flow signal to "bias" or vary the scram setpoint based on total recirculation flow.

The RPS consists of four logic channels. For relay plants (all plants except Clinton), each RPS channel receives two APRM channels. The RPS incorporates a dual trip system design in which both trip systems must be tripped in order to initiate a reactor scram. Each trip system utilizes two redundant trip channels and a trip condition in either channel results in a trip of that trip system. The logic arrangement is designated one-out-of-two- twice logic. A trip condition in either channel A or C coincident with a trip condition in either channels B or D results in reactor scram for BWR/6 plants and for BWR/4 and 5 plants the proper designation is A_1 or A_2 and B_1 or B_2.

For Clinton, the only plant utilizing solid-state RPS logic, each RPS channel receives one APRM channel and scram logic is based on two-out-of-four trip logic.

3.21.3 Setpoint Calculations

The instrument nominal setpoint calculations follow the methodology of Section 1. Initial data include the Analytical Limit (AL) and Operational Limit (OL) specified on the basis of transient performance analyses. The AL and OL, respectively, are chosen such that none of the FSAR transients result in violation of the appropriate safety limits and there is adequate operating margin to provide a reasonable range for maneuvering while avoiding spurious scrams.

The Allowable Value (AV) and the Nominal Trip Setpoint (NTSP) are established following the procedure in Section 1 to account for instrument channel accuracy, accuracy and drift. The procedure for APRM setpoint validation calculations is presented in Section 4.5.

3.21.4 Analysis

The Design Basis Event (DBE) for the high STP scram setpoint is Loss of Feedwater Heating (LFWH) in the manual recirculation flow control mode. The REDY computer code (NRC licensing evaluation model used in the FSAR analysis) was used to simulate this transient. The transients were initiated from full power conditions of 105% NBR steam flow for all plants except Fermi 2, which was initiated from 102% NBR power. The transients are simulated by programming a change in feedwater enthalpy corresponding to a 100°F loss in feedwater temperature. A scram delay (sensor plus logic) time of 0.09 sec was included in the analyses.

The improved SCAT and ISCOR codes (NRC approved licensing evaluation models used in FSAR analysis) were used to determine the MCPR limit and demonstrate adequate margin to the safety limit MCPR.

Results of the analyses are summarized in Table 3.21-1 for a typical plant.

3.21.5 Assumptions and Uncertainties

The following assumptions are used in the determination of the setpoints:

(1)

Table 3.21-1

HIGH SIMULATED THERMAL POWER

(2)

(3)

(4)

(5)

(6)

3.22 LOW CONDENSER VACUUM

3.22.1 Purpose

The purpose of the low condenser vacuum trip of the Main Steam Isolation Valves (MSIVs) is to prevent an overpressure condition in the condenser that could lead to rupture of the diaphragm installed to protect the turbine exhaust hood. The initial reduction in vacuum results in a trip of the main turbine (and if applicable, the feedwater turbine), which in turn causes a reactor scram. Further reduction in condenser vacuum to the MSIV closure trip setpoint results in closure of the turbine bypass valves and the MSIVs.

3.22.2 Trip Logic Description

Four pressure transmitters are furnished on the main turbine condenser. Logic is provided to close the MSIVs when the condenser vacuum drops below the specified setpoint. Each transmitter provides a signal to a trip unit, one for each Channel A, B, C and D.

All plants except Clinton use relay logic for MSIV closure arranged in one-out-of-two-twice logic, for input signals from channels A, B, C and D. For this logic arrangement, all the MSIVs are tripped to close when either or both of Channels A and C, and either or both Channels B and D, provide low vacuum signals at or below the MSIV trip setpoint. The Clinton plant uses solid-state logic for MSIV closure arranged in two-out-of-four logic. For this logic arrangement, all the MSIVs are closed when two or more of the four channels provide low vacuum trip signals.

The MSIV closure logic can be bypassed for plant startup by means of a keylock bypass switch. The Limerick, BWR/5 and 6 plants also require the reactor mode switch to be in the Shutdown, Refueling, or Hot Standby position for the bypass logic to take effect.

3.22.3 Setpoint Calculations

The instrument setpoint calculations follow the methodology of Section 1. Upper and Lower Analytical Limits (AL) are both considered for the MSIV trip function. The upper analytical limit (high vacuum), considered here, limits the reactor vessel pressure transient caused by the closure of the MSIVs to a reasonable level below the appropriate safety limit. The lower analytical limit (low vacuum) protects the condenser against overpressure (insure integrity of turbine exhaust hood diaphragm). The AL is selected on a historical basis so that the minimum difference between the turbine trip and isolation (closure of MSIVs and turbine bypass valves) low vacuum setpoints is at least 10 in. Hg vacuum, including allowances for instrument uncertainties and drift.

The system engineer assigns values to the instrument channel accuracy, calibration accuracy and drift, based on knowledge of system requirements and instrumentation capabilities. The values for instrument accuracy and drift are then confirmed using the methods outlined in Section 2. These values are used in calculating the Allowable Value (AV) and the Nominal Trip Setpoint, from the AL following the procedure described in Section 1. The setpoint calculations are also performed to assure sufficient margin that the Lower Analytical Limit is not exceeded.

The probabilities of Licensee Event Report (LER) avoidance is then calculated using the methods described in Section 1. Calculations of spurious trip avoidance are not performed because of the large margin between normal condenser vacuum and the MSIV closure setpoint.

3.22.4 Analysis

The Design Basis Event (DBE) for low condenser vacuum MSIV trip is the loss of condenser vacuum event. The REDY and ODYN codes (NRC approved licensing evaluation models used in the FSAR analysis) are used to simulate this transient. The transients are initiated from full power conditions of 105% Nuclear Boiler Rated (NBR) steam flow for all plants except Fermi 2, which is initiated from 102% NBR power. The analyses conservatively simulates a

10 inch Hg/sec vacuum decay rate in the main turbine condenser for Grand Gulf, and 2 inch Hg/sec for all other plants. Sensor and logic delays for trip functions are included in the simulation. However, the vacuum difference between the turbine trip and the isolation trips is modeled to correspond to a specified value of 10 inch Hg.

Because the protective actions are actuated at various levels of condenser vacuum, the severity of the resulting transient is directly dependent upon the rate at which the vacuum is lost. Typical loss of vacuum due to single equipment failure (e.g., loss of cooling water pumps or steam jet ejector problem) produces very slow rate of loss of vacuum (minutes, not seconds). If corrective actions by the reactor operators are not successful, simultaneous trips of the main and feedwater turbines (if applicable) will occur, and, ultimately, complete isolation will occur due to closure of the bypass valves (opened with the main turbine trip) and the MSIVs. A faster rate of loss of the condenser vacuum, as simulated in the analysis, reduces the anticipatory action of the scram and the overall effectiveness of the bypass valves, since the system is isolated more quickly.

The low vacuum isolation has the effect of increasing the peak reactor pressure because it shuts off the steam which had been flowing through the turbine bypass valves. The resulting isolation, well after the reactor has been scrammed, produces a mild pressure increase handled easily by the safety relief valves.

The results of the analysis are summarized in Table 3.22-1 for a representative BWR plant.

Table 3.22-1

CONDENSER VACUUM

*The reactor vessel bottom pressure corresponding to ASME moderate frequency event limits.

3.22.5 Assumptions and Uncertainties

The following assumptions are used in the setpoint determination:

(1)

(2)

(3)

(4)

(5)

(6)

3.23 TURBINE CONTROL VALVE FAST CLOSURE

3.23.1 Purpose

The purpose of the turbine control valve fast closure sensors is to provide timely signals that are indicative of the imminent or actual start of fast closure of the turbine control valves. The signals are used to initiate reactor scram and to initiate the trip of the reactor recirculation pumps (if applicable) for events such as generator load rejections which cause fast closure of the turbine control valve.

Generator load rejections require closure of the turbine control valves in order to prevent damage to the turbine that could result from excessive turbine acceleration or turbine overspeed. Turbine protection devices therefore initiate the fast closure of the turbine control valves upon detection of a significant imbalance between the electrical power being generated and the actual load on the generator. Also, for events where a full turbine trip is required, turbine protection devices usually initiate fast closure of not only the turbine control valves but also the turbine stop valves.

Reactor protection is required in order to mitigate the consequences of the ensuing reactor pressurization transient. The required timing is dependent upon the reactor power level at the time the turbine control valves are fast closed, and upon the sizing and operability of the turbine steam bypass system. At low reactor power, the reactor pressure transient is usually small, as steam flow from the reactor is diverted to the turbine bypass system when the turbine control valves are closed, and no reactor shutdown or scram may be needed. If the turbine bypass capacity is insufficient to handle the steam flow being generated by the reactor or if a failure of the turbine bypass system occurs, the Reactor Protection System (RPS) high reactor steam dome pressure scram function and/or the high neutron flux scram function are sufficient and timely enough to mitigate the transient and assure adequate margins to the fuel thermal hydraulic limits and reactor coolant boundary pressure limits.

However, when turbine control valve fast closures occur at high reactor power levels, the reactor pressurization transient is much more rapid, and reactor scram must be initiated earlier in the event to maintain required fuel and reactor coolant boundary safety margins. Reactor scram may also be complemented by immediate trip of the reactor recirculation pumps in order to achieve faster turn around of the reactor power excursion resulting from the pressurization event.

Different turbine protection and control designs by the various turbine vendors, and different designs by even the same vendor, have resulted in several different sensing methods to generate the signal indicating that fast closure of the turbine control valves has occurred or will occur. The most common method is to use pressure switches which monitor control valve trip system hydraulic oil pressure for the individual valves. Other methods are to monitor electrical signals (Fermi 2) generated by the turbine protection system itself, or to monitor the pressure of the control oil from the control valve servos (Grand Gulf).

3.23.2 Trip Logic Description

Four pressure switches interface with the trip logic (except Fermi 2 and Grand Gulf) to cause reactor scram and Recirculation Pump Trip (RPT) if RPT is supplied. Each pressure switch monitors the trip system oil pressure of one of the four turbine control valves and is assigned to one of four trip channels that feed into both the reactor scram and RPT logic circuits.

For plants with relay logic (all except Clinton), the RPS incorporates a dual trip system design in which both trip systems must be tripped in order to initiate a reactor scram. Each trip system utilizes two redundant trip channels, and a trip condition in either channel results in a trip of that trip system. The logic arrangement is designated one-out-of-two-twice logic. A trip condition in either channels A or C coincident with a trip condition in either channels B or D results in reactor scram.

The RPT design as applicable for relay plants also uses two trip systems. However, in this case, the trip of either RPT trip system will result in trip of the recirculation pumps. Two of the four channels are associated with each RPT trip system and trip of both channels of a trip system are required to trip that trip system. This logic arrangement is designated as redundant two-out-of-two logic.

For Clinton, the only plant utilizing solid state logic, the same two-out-of-four trip logic arrangement is used to initiate both reactor scram and RPT.

3.23.3 Setpoint Calculations

Upon initiation of control valve fast closure by the turbine control system (via energization of the fast acting solenoid valve), the trip system oil pressure holding the disc dump valve closed drops from the normal range of 1500-1600 psig to zero within 8 to 10 miliseconds. When control valves are initially full open (i.e., maximum control oil pressure in the hydraulic cylinder), the valves trip system oil pressure must decrease to less than 400 psig before the disc dump valve will open to cause the control valve to start to fast close. For initial control valve positions less than full open, the valves trip system oil pressure must decrease to even lower values before the control valves can start to close. Since the actual analytical limit is the time of start of control valve fast closure and since the control valves can't start to close fast until the oil pressure decreases to 400 psig, the equivalent "analytical limit" established for the pressure switches is 400 psig, decreasing.

Pressure switches are chosen to monitor the trip system oil pressure of the individual turbine control valves for all plants except Grand Gulf and Fermi 2. The equivalent "analytical limit" established for these pressure switches is 400 psig, decreasing. Using this value as a starting point, the instrument setpoint calculations follow the methodology described in Section 1.

The system engineer assigns values to the channel instrument accuracy, calibration and drift, based on knowledge of system requirements and instrumentation capabilities. The Allowable Value (AV) and Nominal Trip Setpoint (NTSP) are obtained from the Analytical Limit by making allowances as described in Section 1. An example is presented in Table 3.23-1. The probabilities of Licensee Event Report (LER) and spurious trip avoidance are then calculated using the methods described in Section 1.

There are no setpoint calculations for Fermi 2, since the RPS receives only digital signals (contact closures) representing the fast closure instruction from, and generated by, the turbine protection system itself.

As mentioned previously, for Grand Gulf the signals representing turbine control valve fast closure are obtained by monitoring the pressure of the control oil from the control valve servos. However, these signals are generated by, and provided to the RPS by AE supplied equipment. Therefore, the methodology used to derive the setpoints is out of the GE scope of responsibility, although the GE specified response time requirement must still be met.

3.23.4 Analysis

The Design Basis Event (DBE) that establishes the actual setpoint requirement as a point in time relative to start of control valve fast closure is the generator load rejection event. The event analysis conservatively assumes coincident failure of the turbine bypass valves. The event is considered in the FSAR to be categorized as an infrequent incident but is conservatively evaluated against the acceptance criteria for moderate frequency events (i.e., Minimum Critical Power Ratio limit of 1.06 and vessel bottom pressure limit of 1375 psig).

The DBE is analyzed with the REDY computer code for Clinton and ODYN (NRC approved licensing evaluation model used in FSAR analysis) for the other plants. The applicability of the River Bend ODYN results to Clinton for pressurization transients is justified in the Clinton FSAR (Section 15.2). Therefore, the River Bend DBE results are applied to Clinton. The transients are initiated from full power conditions, i.e., 105% of Nuclear Boiler Rated (NBR) steam flow for all projects except Fermi 2, which starts from 102% NBR power conditions. The closure characteristics of the turbine control valves are assumed such that the valves operate in the full arc mode and have a full stroke closure time, from fully open to fully closed, of 0.15 sec (0.2 sec for Fermi 2). The resulting closure time from the 105% NBR steam flow condition is typically 70 milliseconds as the control valves operating in the full arc mode are not fully open at the 105% NBR steam flow conditions.

The scram delays and RPT delays (if applicable) are also simulated in the analyzed transients. These delay times simulate the sensor response and the logic and actuating device operating times and are measured from the start of turbine control valve fast closure motion. The setpoints of the process monitored (if applicable) and the equipment comprising the logic and actual trip devices are chosen such that the timing requirements used as the analytical bases are satisfied.

The improved SCAT and ISCOR codes (NRC approved licensing evaluation models used in FSAR analysis) are used to determine the bounding value of Minimum Critical Power Ratio (MCPR) during the transient and to demonstrate adequate margin to the MCPR safety limit.

The results of the analyses are summarized in Table 3.23-1 for a typical plant.

Table 3.23-1

TURBINE CONTROL VALVE FAST CLOSURE

*The reactor vessel bottom pressure corresponding to ASME moderate frequency event limits.

3.23.5 Assumptions and Uncertainties

The following assumptions are made in the setpoint determination:

(1)

(2)

(3)

(4)

(5)

(6)

3.24 TURBINE STOP VALVE CLOSURE

3.24.1 Purpose

The purpose of the Turbine Stop Valve (TSV) position sensors is to provide timely signals that are indicative of the closing action (not fully open condition) of the turbine stop valves. The signals are used to initiate reactor scram and to initiate the trip of the reactor recirculation pumps (if applicable) for events which cause closure of the turbine stop valves.

Turbine trip events require closure of the turbine stop valves in order to prevent damage to the turbine that could result from various abnormal conditions. Turbine protection devices, therefore, initiate the closure of the turbine stop valves upon detection of turbine overspeed, low condenser vacuum, excessive vibration, reactor high water level (Level 8), and other pertinent parameters.

Reactor protection is required in order to mitigate the consequences of the ensuing reactor pressurization transient. The required timing of reactor protection is dependent upon the reactor power level at the time the turbine stop valves are closed, and upon the sizing and operability of the turbine steam bypass system. At low reactor power, the reactor pressure transient is usually small, since steam flow from the reactor is diverted to the turbine bypass system when the turbine stop valves are closed, and no reactor shutdown or scram may be needed. If the turbine bypass capacity is insufficient to handle the steam flow being generated by the reactor or if a failure of the turbine bypass system occurs, the Reactor Protection System (RPS) high reactor steam dome pressure scram function and/or the high neutron flux scram function are sufficient and timely enough to mitigate the transient and assure adequate margins to the fuel thermal hydraulic limits and reactor coolant boundary pressure limits.

However, when TSV closure occurs at high reactor power, the reactor pressurization transient is much more rapid, and reactor scram must be initiated earlier in the event to maintain required fuel and reactor coolant boundary safety margins. Reactor scram may also be complemented by immediate trip of the reactor recirculation pumps in order to achieve faster turnaround of the reactor power excursion resulting from the pressurization event.

3.24.2 Trip Logic Description

For relay plants (all except Clinton), eight limit switches interface with the trip logic used to cause reactor scram and Recirculation Pump Trip (RPT) if RPT is supplied. These switches, which indicate the open or not-fully-open conditions of the stop valves, are arranged two per valve, each of the switches being assigned to a different RPS trip channel. Grand Gulf uses pressure switches which monitor the oil pressure instead of TSV position switches.

For relay plants, the RPS incorporates a dual trip system design in which both trip systems must be tripped in order to initiate a reactor scram. Each trip system utilizes two redundant trip channels, and a trip condition in either channel results in a trip of that trip system. The logic arrangement is designated one-out-of-two-twice logic.

The TSV closure trip logic for relay plants is arranged such that one or two turbine stop valves can be in the not-fully-open positions (for test purposes) without causing a reactor scram, provided the power has been reduced sufficiently to limit reactor pressure and steam flow. A full RPS trip (reactor scram) will result whenever three or more turbine stop valves are in the not-fully-open positions (provided that the reactor power is above the equivalent turbine first-stage pressure bypass for TSV closure and turbine control valve fast closure trips).

The RPT design for relay plants (as applicable) also uses two trip systems. However, in this case, the trip of either RPT system will result in trip of the recirculation pumps. Two of the four RPS channels are associated with each RPT system, and trips of both RPS channels associated with a RPT trip system are required to trip that trip system. This logic arrangement is designated as redundant two-out-of-two logic.

For Clinton, the only plant utilizing solid-state trip logic, only one limit switch per stop valve is used, each being assigned to a unique RPS division. The same two-out-of-four trip logic arrangement is used to initiate both reactor scram and RPT. Thus, only two turbine stop valves need be in the not-fully-open positions in order to cause a reactor scram.

3.24.3 Setpoint Calculations

Historically, the Analytical Limit (AL) has been chosen to be the 90% open position. Analyses have been performed using the AL to demonstrate that the FSAR transients which use the TSV closure trip setpoint do not violate the appropriate safety limits.

The instrument setpoint calculations used to determine the Nominal Trip Setpoint (NTSP) and the Allowable Valve (AV) for turbine stop valve closure trip follow the methodology described in Section 1. The system engineer assigns values to the instrument loop accuracy, calibration and drift based on knowledge of the instrument capabilities and system requirements. These values are then used in the setpoint determination. The Licensee Event Report (LER) avoidance is also determined using methods in Secion 1.

3.24.4 Analysis

Two Design Basis Events (DBE) apply to the TSV closure trip. The feedwater controller failure to maximum flow demand is the DBE for the Minimum Critical Power Ratio (MCPR) safety limit, and the turbine trip event is the DBE for the maximum reactor pressure safety limit. The turbine trip is conservatively assumed to include failure of 50% of the turbine bypass system capacity (13% NBR Steam Bypass Flow and 10% NBR Reheater Flow) for Fermi 2, and total failure of the bypass system capacity for the other plants.

The turbine trip event with failure of the bypass system is considered by GE to be categorized as an infrequent incident, but is conservatively required by the NRC to be compared in the FSAR to the criteria for moderate frequency events (i.e., MCPR safety limit of 1.06 and maximum vessel pressure safety limit of 1375 psig).

These DBEs were analyzed with the REDY computer code for Clinton and the ODYN code (NRC approved licensing evaluation models used for FSAR analysis) for the other plants. The applicability of the River Bend FSAR ODYN results to Clinton for pressurization transients is justified in the Clinton FSAR (Section 15.2). Therefore, the River Bend turbine trip results are applied to Clinton. The transients were simulated with protective functions assumed to operate at appropriate analytical limits. The transients were initiated from full design power conditions of 105% Nuclear Boiler Rated (NBR) steam flow for all plants except Fermi 2, which was initiated from 102% NBR power. For the analysis, conservative TSV closure times, (typically 0.1 sec), were used. Appropriate delay times (sensor plus logic) for the scram and for the RPT (if applicable) functions were also simulated. The delay times are measured from the time the TSVs reach the trip setpoint until initiation of the respective function.

The results of the analyses are summarized in Table 3.24-1 for a typical plant.

3.24.5 Assumptions and Uncertainties

The following assumptions were made in the setpoint determination:

(1)

(2)

(3)

Table 3.24-1

TURBINE STOP VALVE FAST CLOSURE

*The reactor vessel bottom pressure corresponding to ASME moderate frequency event limits.

(4)

(5)

(6)

3.25 TURBINE FIRST STAGE PRESSURE

3.25.1 Purpose

The turbine first stage pressure sensors are used for an indirect measurement of reactor power. They provide an automatic bypass of the Turbine Stop Valve Closure (TSVC) and Turbine Control Valve Fast Closure (TCVFC) reactor scram and Recirculation Pump Trip (RPT) functions (if applicable) at low reactor power levels where an immediate scram from closed or closing turbine valves is not required. The trip bypass is in effect whenever Turbine First Stage Pressure (TFSP) is below a specified value, and thus permits continued reactor operation with the turbine stop valves and/or turbine control valves closed. At the lower reactor power levels, the reactor pressurization transients resulting from TSVC or TCVFC are usually small, as steam flow from the reactor is diverted to the condenser via the turbine steam bypass system when the turbine stop or control valves are closed, and no reactor scram may be needed. In the event of inadequate turbine bypass capacity or failure of the turbine bypass system, adequate reactor protection is provided by the diverse high reactor dome pressure or high neutron flux scram functions.

Safety requirements related to this trip bypass are that the TSVC and TCVFC trip functions are enabled (i.e., bypass removed), at or before exceeding 30% of rated reactor power for Hope Creek, Limerick, Nine Mile Point 2; at or before exceeding 36% of rated reactor power for Fermi 2; and at or before exceeding 40% of rated reactor power for Clinton, Perry, River Bend and Grand Gulf. The reactor power levels are design basis values chosen primarily for the purpose of permitting the capability of continued low power reactor operation with turbine stop and/or control valves closed and with reactor steam flow diverted through the turbine bypass valves. Turbine valve closure transients are evaluated in the Final Safety Analysis Report and full power events are considered to be bounding.

Turbine first stage pressure has been historically used as the parameter to approximate reactor power and effect the actual trip bypass. The Reactor Protection System (RPS) design purposely chooses this parameter, as opposed to the more direct measurement of power such as neutron flux, in order to assure diversity between the TSVC and TCVFC scram functions and the neutron flux scram function.

3.25.2 Trip Logic Description

Four pressure sensors are connected to the high pressure turbine via instrument lines to monitor either turbine bowl pressure or turbine first stage shell pressure. The choice is dependent upon characteristics of turbine operation. The pressure being monitored varies essentially linearly with turbine throttle flow over the full range of turbine operation.

All plants associated with this study utilize pressure transmitters and trip units. The transmitters, located in the turbine building, are calibrated with a span range from 0 to 100% of the plant unique value of turbine first stage pressure that results at Valves Wide Open (VWO) turbine throttle flow. Each of the four transmitter/trip unit sets is associated with one of the four RPS logic channels. The TSVC and TCVFC trips for an individual RPS channel are bypassed as long as the input from the pressure transmitter is below the setpoint of the trip unit associated with that RPS channel. The trip units are adjusted to remove the bypass condition (i.e., enable the TSVC and TCVFC trip functions) when increasing turbine first stage pressure (i.e., increasing reactor power) passes the appropriate setpoint.

The logic arrangements used to bypass the TSVC and TCVFC reactor scram and, when applicable, RPT functions are essentially the converse of the logic used to cause the trips.

For plants with relay logic (all except Clinton), where the RPS incorporates a dual trip system design in which both trip systems must be tripped in order to initiate a reactor scram, the trip bypass logic arrangement must thus only prevent the trip of one of the two trip systems in order to bypass the reactor scram at low reactor power levels. However, since each trip system has two redundant trip channels, both channels of either of the two RPS trip systems must be in a bypassed state in order to bypass the TSVC and TCVFC trip functions. These trip functions are thus bypassed if the turbine first stage pressure trip bypass trip units of both channels A and C are in the bypassed state or if the trip units of both channels B and D are in the bypassed state for Perry, River Bend and Grand Gulf. For Hope Creek, Limerick, Fermi 2 and Nine Mile Point 2, the trip functions will be bypassed when A_1 and A_2 are in the bypassed state or B_1 and B_2 are in the bypassed state. Such bypass logic arrangement is designated two-out-of-two per trip system. Under normal conditions of low power operation, all four transmitters would be monitoring low turbine first stage pressure, and both trip systems would be bypassed. The bypass resulting from a single turbine first stage pressure trip unit affects only the TSVC and TCVFC trip functions of a single RPS channel. No other trip functions (e.g., high neutron flux or high reactor dome pressure) in that RPS channel are affected.

The turbine/generator trip RPT function, which is initiated on most plants from TSVC or TCVFC at high reactor power levels, is also a dual trip system design for the relay plants. However, in this case, the trip of either RPT trip system results in trip of the recirculation pumps. Thus, for projects which have this trip function, both RPT trip systems must be bypassed to bypass the trip of the recirculation pumps. For the majority of relay projects, the trip bypass logic requires that all four trip units be in the bypassed state to effect the low power bypass of the TSVC and TCVFC RPT function.

Clinton (the only plant with solid state logic) utilizes two-out-of-four channel trip logic to cause both reactor scram and RPT upon TSVC and TCVFC from high power levels. The trip bypass logic arrangement used to bypass these trip functions at low reactor power levels requires that at least three of the four turbine first stage pressure trip bypass channels be in the bypassed state to effect the bypass of both the scram and RPT trip functions.

3.25.3 Setpoint Calculations

Prior to performing setpoint calculations, additional evaluations are required to determine appropriate values of Turbine First Stage Pressure (TFSP) that are conservatively equivalent to the Analytical Limit (AL) or reactor power. A generic evaluation was used for BWR/6 plants (Grand Gulf, Clinton, Perry, River Bend) to establish the values of TFSP that are conservatively equivalent to 40% of rated reactor power. Unique evaluations were used to establish the TFSP values that are conservatively equivalent to 30% of rated reactor power for Limerick, Hope Creek, Nine Mile Point 2 and 36% of rated reactor power for Fermi 2. These evaluations consider the non-linear relationship of reactor vessel steam flow to reactor power level and, also, conservatively account for the steam flow used for reheaters, feedwater turbines, steam jet air injectors and valve stem sealing purposes. The evaluation process thus involves determining the minimum vessel steam flow corresponding to the applicable reactor power level, subtracting a conservative estimate of the steam flow not passing through the high pressure turbine and then ratioing this remaining steam flow to the steam flow that exists at turbine VWO conditions. This resulting value is also the ratio of TFSP at the chosen reactor power level to the TFSP at VWO conditions. By requiring that the transmitters' spans be calibrated from 0 to 100% of the plant-unique values of TFSP at VWO conditions, the resulting ratios (in terms of percent of VWO TFSP) are thus the conservatively determined equivalents to the design basis values of rated reactor power. These equivalent values are used as the starting points for the calculations setpoints following the methodology described in Section 1.

The system engineer assigns values to the instrument accuracy, calibration and drift, based upon knowledge of system requirements and instrumentation capabilities. The values assigned for instrument accuracy and drift are then confirmed using the methods in Section 2. The Allowable Value (AV) and Nominal Trip Setpoint (NTSP) are obtained from the AL by making allowances as described in Section 1. The probability of Licensee Event Report (LER) avoidance is also calculated using the methods described in Section 1.

3.25.4 Analysis

The Design Basis Event (DBE) for TFSP bypass of TSVC and TCVFC trips is the generator load rejection event with turbine bypass failure. This event is categorized as an infrequent event, but is conservatively evaluated against the acceptance criteria for moderate frequency events [i.e., Minimum Critical Power Ratio (MCPR) safety limit of 1.06 and vessel bottom pressure of 1375 psig].

The ODYN code (NRC approved licensing evaluation model used in FSAR analysis) was used to simulate these DBEs for typical plants of each BWR class. The transients were initiated from 30% of nuclear boiler rated (NBR) power for Nine Mile Point 2, Limerick, and Hope Creek; 36% NBR for Fermi 2; and 40% NBR power for Clinton, Grand Gulf, Perry and River Bend. The closure characteristics of the turbine control valves are assumed such that the valves operate in the full arc mode and have a full stroke closure time, from fully open to fully closed, of 0.15 second (0.2 sec for Fermi 2). No credit was taken for the neutron flux scram since that signal may or may not reach its trip setpoint. Scram, in this situation, is conservatively initiated from the reactor dome high pressure analytical limit setpoint. Appropriate delay times (sensor plus logic) are included in the analysis.

The improved SCAT and ISCOR codes (NRC approved licensing evaluation models used in the FSAR analysis) were used to determine the bounding values of MCPR during the transients and to demonstrate adequate margin to the MCPR safety.

Results of the analyses are presented in Table 3.25-1 for a typical plant.

Table 3.25-1

TURBINE FIRST-STAGE PRESSURE

*For this example scale of 0 to 100% of Valves Wide Open (VWO) corresponds to a scale of 0 to 701.5 psig turbine first-stage pressure.
**The reactor vessel bottom pressure corresponding to ASME moderate frequency event limits.

3.25.5 Assumptions and Uncertainties

The

(1)

(2)

(3)

(4)

(5)

(6)

4.0 NRC OPEN ITEMS

This section of the report contains the General Electric responses to the NRC letter on Instrument Setpoint Methodology (letter to Mr. John Carolan from the Nuclear Regulatory Commision subject "Instrument Setpoint Methodology for General Electric Supplied Protection System Instrumentation" dated May 15, 1984.) The reponses to the NRC letter are organized according to the open item numbers assigned by the NRC in their letter.

4.1 NRC OPEN ITEM 5.1 - ENVIRONMENTAL EFFECTS

This responds to Item 5.1 of the NRC Staff Report dated May 15, 1984 titled "Transmittal of NRC Staff Report of Setpoint Methodology for General Electric Supplied Protection System Instrumentation". The NRC staff recommends that the effect of drywell temperatures on instrument sensing lines should be considered, utilizing guidance and information from BWR Owners' Group Reports.

4.1.1 Response

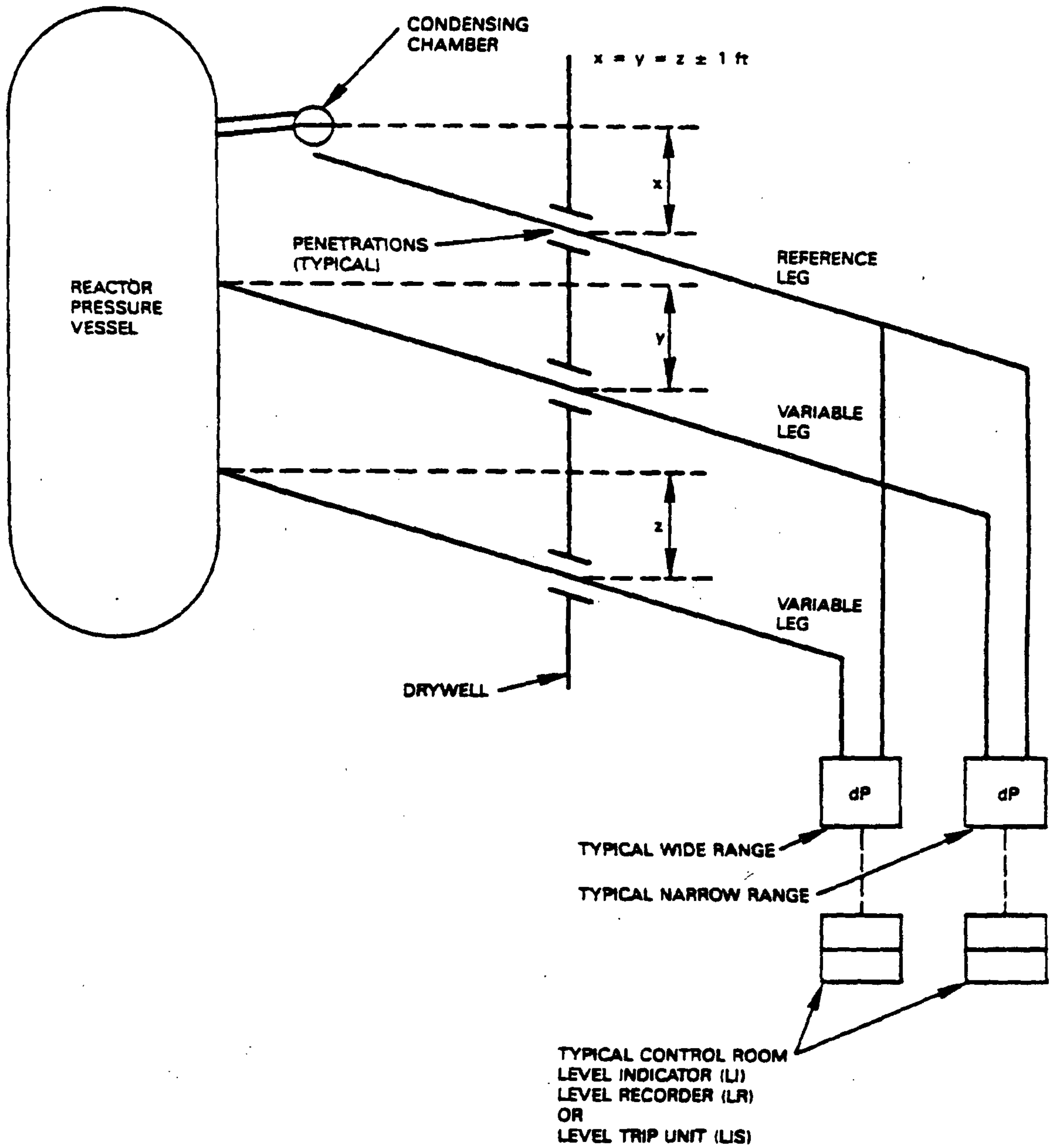


Figure 4.1-1 Drywell Instrument Line Arrangement

The second portion of NRC Question 5.1 requested an evaluation of the adequacy of the equations used for statistical summation of errors applicable for a normal environment versus the uncertainties associated with possibly dependent effects of off-normal or harsh conditions.

4.1.2 Error Analysis

4.2 NRC OPEN ITEM 5.2 - VALIDATION OF DESIGN ALLOWANCES

The validation of design allowances is presented in this report using a typical plant. Specific information for each utility will be submitted on an individual basis.

4.3 NRC OPEN ITEM 5.3 - ALLOWABLE VALUES

This responds to Item 5.3 of the NRC Staff Report dated May 15, 1984 entitled "Transmittal of NRC Staff Report of Setpoint Methodology for General Electric Supplied Protection System Instrumentation". In Item 5.3 of the subject report the NRC Staff recommends that the difference between the technical specification's value of trip setpoint and allowable value include only the drift allowance for that portion of the instrument checked during the monthly setpoint verification.

The context of the NRC Staff recommendation was the observation that the typical instrument loop consists of both a transmitter and a trip unit. The transmitter is generally tested on an 18-month surveillance interval. The trip unit is generally tested more frequently, and in many cases monthly. Thus, at the time of trip unit surveillance testing, using an input signal direct to the trip unit, any inaccuracies or drift present are due only to the trip unit and not the transmitter. The NRC Staff was concerned that this would result in a situation where the trip unit drift is excessive, but corrective action is not taken because the difference between the technical specification value and allowable value includes allowances for the transmitter as well.

General Electric Company has reviewed the Staff concern and concludes that the existing procedure of using a single technical specification value and single allowable value, based on the total instrument loop, is acceptable. This conclusion is based on the following three points:

(1)

(2)

(3)

Figure 4.3-1 Typical Design Relationships

Figure 4.3-2 Idealized Worst Case

Figure 4.3-3 Realistic (Conservative) Case

4.3.1.4 Evaluation of the Models

Table 4.3-1

Table 4.3-2

Table 4.3-3
Potential Cases for Figure 4.3-3

Table 4.3-4

PROBABILITIES for FIGURE 4.3-2

Table 4.3-5

PROBABILITIES for FIGURE 4.3-3

4.4 NRC OPEN ITEM 5.4 - EXPANDING MANUFACTURERS PERFORMANCE SPECIFICATIONS

4.4.1 Introduction and Summary

On January 31, 1984, a presentation was made to members of the NRC staff concerning instrument setpoint methodology. This presentation included limited information on field data used to validate the application of manufacturers performance specifications for drift in developing design allowances for drift intervals exceeding six months. Open Item 5.4 is a staff recommendation that drift assumptions for Rosemount devices be validated using field data for surveillance intervals up to 18 months.

The purpose of this section is to present the results of the General Electric evaluation of field data on performance of Rosemount transmitters and trip units in relation to the design assumptions for drift embodied in Sections 1 and 2 of this report.

This section presents the demonstration that field calibration data support surveillance intervals well beyond 18 months. The demonstration is presented in the following subsections:

(1) Subsection 4.4.2: This section describes schematically how typical calibration data are taken for transmitters and trip units.

(2) Subsection 4.4.3: In this section the nature of calibration data is examined so that a method can be developed for confirming that the data demonstrate conformance to the design allowances in the Instrument Setpoint Methodology. This method, including its basis in statistics, is described in this section.

(3) Subsections 4.4.4, 4.4.5 and 4.4.6: In these sections the calibration data base for transmitters is described, calculation

of design allowances for field data is discussed, and the data base is evaluated to demonstrate conformance to the design allowances.

(4) Subsections 4.4.7, 4.4.8 and 4.4.9: In these sections the calibration data base for trip units is described, calculation of design allowances for field data is discussed, and the data base is evaluated to demonstrate conformance to the design allowances.

(5) Subsection 4.4.10: Conclusions are given in this section.

(6) Subections 4.4.12: This subsection contains a glossary for special terms used in Section 4.4 of this report.

4.4.2 Typical Normal and Calibration Configurations for Transmitters and Trip Units

Typical normal and calibration configurations for transmitters and trip units are illustrated in Figure 4.4-1. The normal configuration for plant service is shown on the left. The calibration configurations for transmitters and trip units separately are shown on the right.

For calibration, input for a transmitter is a known calibration physical pressure source; output is a signal in milliamps. The strength of the output signal is adjusted to conform to a standard calibration relationship, as required. Input for a trip unit is a known signal in milliamps (or millivolts); output is a "trip" signal which is either on or off. The level of the input signal at which trip occurs reflects the correct calibration of the trip unit. This trip point is adjusted as required.

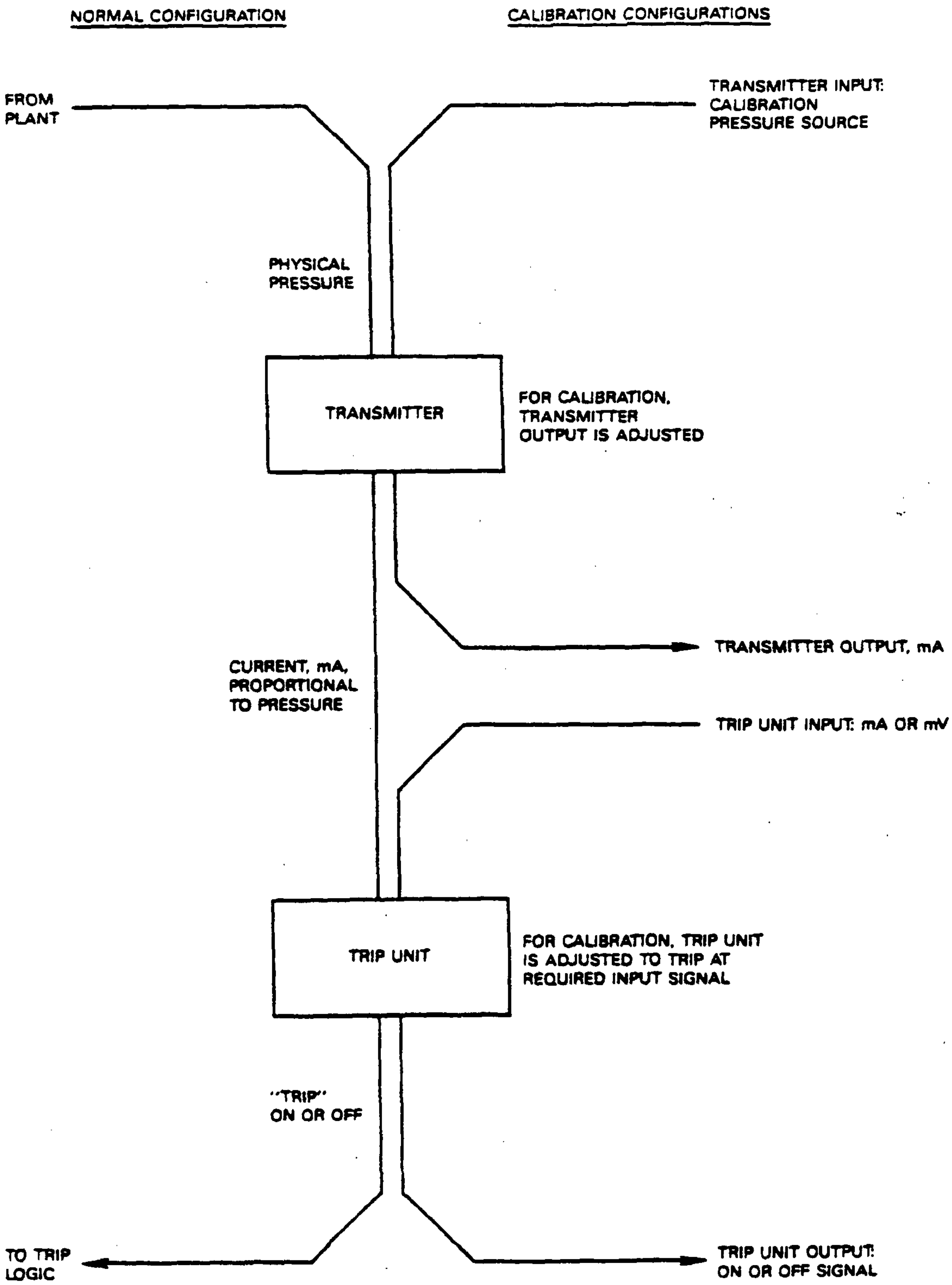


Figure 4.4-1 Typical Normal and Calibration Configurations for Pressure Transmitters and Trip Units

4.4.3 The Confirmation Method

4.4.3.1 Introduction

In this section we develop the confirmation method for demonstrating that plant performance of transmitters and trip units in Rosemount pressure instrument systems is within the applicable design allowances. We will begin by examining the nature of the data base in Subsection 4.4.3.2, noting the dimensions of the Observed In-Service Differences (OISDs) between subsequent calibration checks from the data base in Subsection 4.4.3.3, and writing a model for OISDs in Subsection 4.4.3.4. In Subsection 4.4.3.5 we will derive design allowances appropriate to the OISDs. In Subsection 4.4.3.6 we will describe the confirmation method in detail, step by step, and we will summarize the principles of the confirmation method in Subsection 4.4.3.7.

A glossary of special terms used in this section is given in Section 4.4.11. Terms related to Setpoint Methodology are as defined in Sections 1 and 2.

4.4.3.2 The Nature of the Data Base

The data base, which is described more fully in Section 4.4.4 for transmitters and Section 4.4.7 for trip units, consists of hundreds to thousands of pairs of Individual Observed Calibration Values. Each pair consists of an as-left value at a previous calibration time and an as-found value at a later time. At any one calibration time, the as-found and as-left Individual Observed Calibration Values will be the same if no calibration adjustment was made; otherwise they will differ. In overview, these pairs were taken as follows:

(1) At the following three plants over the measurement years shown:

(a) Nine Mile Point 1 (Niagara Mohawk Power Corporation), a BWR/2 plant 1979-1981 (trip unit data only).

(b) Peach Bottom 2&3 (Philadelphia Electric Company), BWR/4 plants, 1975-1980 and 1983-1985.

(c) Grand Gulf 1 (Mississippi Power & Light Company), a BWR/6 plant, 1981-1984.

(2) From a total of approximately 60 instruments consisting of both absolute pressure transmitters and differential pressure transmitters and trip units used in pressure switch, differential pressure switch and level switch applications.

(3) At two or more calibration times separated by 1 to 18 months for transmitters, and by approximately one month for trip units.

Figure 4.4-2 Model for Observed In-Service Differences (OISDs)

4.4.3.5 Design Allowances for OISDs

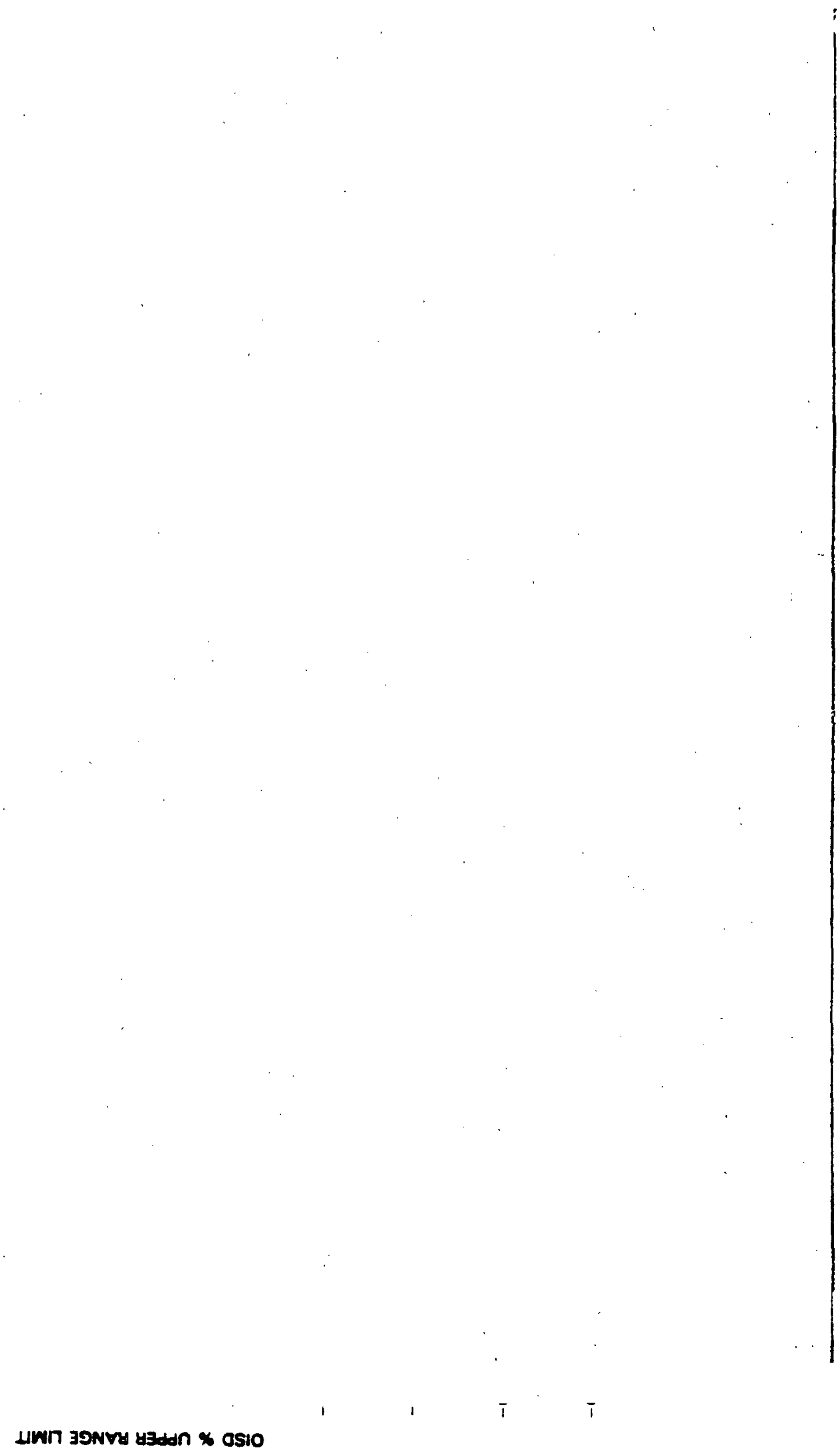
The first set of data was collected by operating personnel during normal transmitter surveillance (calibration checks) at Peach Bottom 2 and 3 (BWR/4 plants) over two time periods. The first time period was 1975-1980, when the Rosemount transmitters were first installed in the plants, and the second was when additional data were collected on the same plants during the course of the Setpoint Methodology Program (from late 1983 to 1985).

The second set of data was collected at Grand Gulf 1 (BWR/6) over the period of 1981-1984.

4.4.4.2 Data Excluded from the Data Base

From the foregoing it can be seen that nearly all data confirm that installed transmitters are performing with less error than the design allowances. In particular, the results show that surveillance intervals significantly longer than 24 months are feasible, using the design allowances for the longer time intervals derived as in Section 2 (Equation 6 herein). Thus, Nominal Trip Setpoints based on design allowances for the longer time intervals are anticipated to provide the intended protection.

4.4.6.3 Estimate of Mean Drift


OISD % UPPER RANGE LIMIT

4.4.7. Description of the Calibration Data Base for Trip Units

4.4.7.1 Data Sources

The trip unit data base consists of actual in-plant data taken from three sources.

The first set of data was taken from Rosemount trip units in Nine Mile Point 1 (BWR/2), from 1979 to 1981. These data were collected as part of an early effort to track the performance of the trip units.

The second set of data was collected at Peach Bottom 2 and 3 (BWR/4s) during the course of the Setpoint Methodology Program (i.e., from late 1983 to 1985).

The third set of data was collected at the Grand Gulf 1 (BWR/6) over the period of 1981-1984.

4.4.7.2 Data Excluded From The Data Base

All the data from Nine Mile Point 1, Peach Bottom 2 and 3, and Grand Gulf 1 that was sufficiently complete to provide OISD data was used in the evaluation, with one exception.

4.4.10. Conclusions

The following four conclusions can be drawn on the basis of the groups of Rosemount devices evaluated in this analysis:

(1) Rosemount absolute and differential pressure transmitters have nearly always operated within the design allowances for the field

(2) Rosemount trip units have always operated within design allowances for the field data.

(3) Surveillance intervals up to 24 months and beyond are feasible for both transmitters and trip units, without exceeding design allowances.

(4)

4.4.11 Glossary

NOTE: This Glossary is supplemental to the terms defined in Sections 1 and 2 for the Setpoint Methodology.

Accuracy Error (e_{acc}): The particular "random draw" from the distribution of accuracy errors which, from time to time, reflect the "accuracy state" of the instrument. Generally, encompasses only "short-term" errors due to physical causes which take on new error values after "short" periods of time (Channel Instrument Accuracy, Section 2).

As-found: Denoting the beginning of a calibration check, prior to any adjustment, as the time when a calibration value is obtained or applies.

As-left: Denoting the end of a calibration check, following any adjustment made, as the time when a calibration value is obtained or applies.

Average True Calibration Value: The calibration value of an instrument

Calibrated Span: The interval, on either the scale of the input physical variable or of the output electrical signal analog, over which the instrument is calibrated. The Calibrated Span can be equal to or less than the Upper Range Limit, as illustrated in Figure 4.4-7.

Calibration Error: A random value drawn from a distribution whose members characterize the "calibration state" of the instrument whenever a calibration check is carried out. A particular value is designated e_{cal}. The design allowance (for the channel) is found in Reference 15 (Channel Calibration Accuracy, Sections 1 and 2).

Calibration Time Interval: See Time Interval.

Calibration Time: The date and time when a calibration check is performed.

Calibration Value: Generically, an input or, more often, an output value of an instrument related to a calibration check.

Figure 4.4-7 Typical Relationship Between Calibrated Span and Upper Range Limit for a Transmitter

Data Base Cell: A part of the data base having a single value for each of the following properties:

(1) Instrument Category
(2) Relationship of Upper Range Limit to Calibrated Span
(3) Calibration Time Interval

A Data Base Cell may include data from more than one plant.

Design Allowance: The acceptable limit applicable to accuracy, channel calibration accuracy and drift separately, and, when combined appropriately, to the OISD. Design allowances for accuracy and drift are stipulated in Section 2, and for calibration in Reference 15.

Drift: Together with accuracy and calibration capability, one of the

Temperature Effect on Drift: This type of instrument error reflects the

<u>Error</u>: The magnitude of departure of an observed from a true value. An error is positive when the observed value exceeds the true value, and is negative when the observed value is less than the true value, algebraically.

<u>Individual Observed Calibration Value</u>: This is the measured value (i.e.,,

<u>Individual True Calibration Value</u>: This would be the indicated value from the instrument at the time of a calibration check if there were no calibration error, only an accuracy error. Illustrated by the solid circles in Figure 4.4-2.

<u>Instrument Category</u>: There are three categories of use of Rosemount instruments. The transmitters are used as absolute or gauge pressure transmitters and differential pressure transmitters, the latter including level transmitters. For the trip units, no distinction is made because all trip units are physically the same and operate on the basis of an electrical input signal, regardless of category of the transmitter generating the input signal.

<u>Intended Calibration Value</u>: This is the measured (indicated) value which is planned to correspond to a certain value of the physical variable.

<u>Mean</u>: Same as the arithmatic average. Calculated as $\bar{x}$ =(sum of all x_i)/n.

Observed In-Service Difference, OISD: This is the difference from an Individual Observed Calibration Value as-left at a previous calibration check to the Individual Observed Calibration Value as-found at a later calibration check. The OISD is positive if the Individual Observed Calibration Value has increased algebraically between the two calibration

Span: See Calibrated Span.

Standard Deviation: The square root of the variance; the usual statistical measure of variability about the mean, being in linear units.

Surveillance Check: See Calibration Check.

Surveillance Interval: See Time Interval.

Time Interval: The period of time between successive calibration checks (i.e., between successive calibration times).

Upper Range Limit: This is the interval on the scale of the physical variable over which the instrument can be used (see Figure 4.4-7).

Variance: This statistical property is the square of the standard deviation, and is the second moment about the mean of data. Herein, estimated by s^2 = (Sum of all $(x_i-\bar{x})^2$)/(n-1).

4.5 NRC OPEN ITEM 5.4b - APRM VALIDATION CALCULATIONS

On January 31, 1984, a presentation was made to members of the NRC staff concerning instrument setpoint methodology. An example of instrument setpoint validation calculations for confirming the analytic limit was shown using the APRM system. Open Item 5.4b was generated from the NRC because the sources of the bias and variability values used in the calculations were not identified. The staff recommended that the values used be supported by field data where applicable.

In the presentation, Figure 4.5-1 and Table 4.5-1 were shown. In response to NRC Item 5.4b, GE has not only examined manufacturer's performance data and field data, but clarified the description of the methodology, resulting in Figure 4.5-2 and Table 4.5-2.

This section describes the source and treatment of manufacturer's and field data to justify Figure 4.5-2 and Table 4.5-2. The approach described is generic; however, the specific data in Table 4.5-2 is for Limerick.

Definitions for Figure 4.5-3:

Figurē 4.5-3 Theoretical Model of Sensor Sensitivity

Definition for Figure 4.5-4

TOTAL CORE FLOW (percent rated)

Figure 4.5-5 Theoretical Model of APRM Tracking

Figure 4.5-6 Statistical Model for LPRM/APRM Signal Cond. Equipment

4.5.8 Conclusion

The source and treatment of manufacturer's and field data described herein justifies Figure 4.5-2 and Table 4.5-2. The new table and figure are clarification of what was presented to the NRC in January 1984 (Figure 4.5-1 and Table 4.5-1). The approach in determining the individual uncertainties as presented in the previous pages is generic, but has been applied to Limerick only in Tables 4.5-1 and 4.5-2.

The instrument setpoint validation for confirming the analytical limit was shown to the NRC in the January meetings. Based on the review of the Manufacturer's and field data and the clarification of Figure 4.5-1 (as presented in Figure 4.5-2), the generic setpoint validation presented to the NRC is still valid.

4.6 NRC OPEN ITEM 5.5 CALIBRATION ERROR VALIDATION

General Electric has specified the calibrational error allowances in the applicable Design Specification Data Sheets. Selection of procedures and equipment as required to meet the specified values is the responsibility of the individual utility.

4.7 NRC OPEN ITEM 5.6 - STATISTICAL METHODS

This response addresses the NRC suggested expression given on page 19 of the NRC letter "Instrument Setpoint Methodology for General Electric Supplied Protection Instrumentation"dated May 15 1984, which is as follows:

Expression 1

$$[(\text{sensor drift} + \text{human factor calibration considerations} + \text{calibration equipment inaccuracy} + \text{error band allowed by procedure})^2 + (\text{trip unit drift} + \text{human factor calibration considerations} + \text{calibration equipment inaccuracy} + \text{error band allowed by procedure})^2 + (x)^2 + (y)^2 + (z)^2]^{\frac{1}{2}}$$

4.8 NRC OPEN ITEM 5.7 - COMPUTER CODE MODELLING CONSERVATISMS

Early in 1984, a presentation was made to members of the NRC staff concerning instrument setpoint methodology. In some of the examples utilized, some modelling conservatisms were claimed as part of the material which showed margins to safety limits. The NRC has initiated an open item from that exchange, challenging the model conservatism claims. This section is intended to document the bases of the values GE believe represent the model conservatisms that are appropriate for use in this setpoint methodology review. Several areas were mentioned. They will be addressed individually.

4.8.1 Model Conservatism for Peak Pressures

Table 4.8-1

COMPARISION of ODYN PEAK PRESSURE PREDICTIONS with TEST DATA

TEST P_T	ODYN P_m	MC[a]	REFERENCE[b]		ΔP_R [c]
psia	psia	psi	Table	Figure	psi

4.8.2 Model Conservatism for Thermal Margin During Fast Recirculation Increase Events

In conclusion, the 0.10 conservatism value is clearly a cautious claim for use in the setpoint methodology evaluation.

Table 4.8-2

REDY MODEL CONSERVATISM for RECIRCULATION FLOW INCREASE EVENT

4.8.3 Model Conservatism for the Loss of a Feedwater Heater Transient

Table 4.8-3

MODEL CONSERVATISM for LOSS of FW HEATING EVENT

4.9 NRC OPEN ITEM 5.8 - SAFETY LIMITS

Early in 1984, a presentation was made to members of the NRC Staff concerning instrument setpoint methodology. In one of the transients shown the high reactor pressure scram was utilized as the scram initiator after failure of two other scram methods. The peak reactor pressure during this transient was compared to a safety limit. The safety limit shown was the ASME Emergency Limit (Service Level C). The NRC initiated an open item expressing their concern with this limit since it was beyond the ASME upset overpressure limit (Service Level B) defined in the specifications for each plant.

4.9.1 Response

Previously performed analysis shows that the pressure scram setpoint is acceptable and even provides margin to the Service Level B limit of 1375 psig though the scenario only needs to meet Service Level D limits.

4.10 NRC OPEN ITEM 5.9 - SETPOINTS OUTSIDE GE NSSS SCOPE

The setpoints that are outside the scope of GE are the responsibility of the individual utilities and they will assure that the safety criteria have been met (as applicable).

5.0 REFERENCES

1. L. E. Lee, G. W. Burnette, R. Muraledharam, and B. Schneidman, "Comparison of LOCA Evaluation Models Predictions with Blowdown Heat Transfer Results", General Electric Company, March 1978 (NEDO-21836).

2. Memorandum, P.S. Check to T. Novak and R.L. Tedesco, "Safety Evaluation for 'Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors', NEDO-24154 and NEDE-24154 P, Volumes I, II and III", NRC, October 22, 1980.

3. Memorandum, P.S. Check to T. Novak and R.L. Tedesco, "Supplemental Safety Evaluation for ODYN Code", November 20, 1980.

4. Letter, B. J. Youngblood (NRC) to J. F. Carolyn (LRG), "Interim Staff Evaluation Findings Pertaining to Setpoint Methodology for General Electric Supplied Protection Systems Instrumentation", February 19, 1985.

5. R. B. Linford, "Analytical Methods of Plant Transient Evaluation for the General Electric Boiling Water Reactor", General Electric Company, February 1973 (NEDO-10802).

6. ASME, Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, Division 1, Appendix G, Paragraph G-2214.3, 1972 Edition 1.

7. Letter, J.S. Charnley (GE) to F.J. Miraglia (NRC), "Loss of Feedwater Heating Analysis", July 5, 1983.

8. "Assessment of BWR Mitigation of ATWS, Volume II (NUREG 0460 Alternate No. 3)", General Electric Company, February 1981 (NEDE-24222).

9. "Full-Scale Installation, Operation and Qualification of Elbow Flow Meters in the Main Steam Lines of Millstone Power Station," General Electric Company, February 1980, (NEDE-25274).

10. Letter to ALL BWR licensees of Operating Reactors, From USNRC Subject "Reactor Vessel Water Level Instrumentation in BWRs" (Generic Letter No. 84-23), October 26, 1984.

11. General Electric Company Design Spec Data Sheets for each respective system and plant application.

12. "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors" Volume 2, General Electric Company, October 1978, (NEDO-24154).

13. "General Electric Standard Application for Reactor Fuel (United States Supplements)", (GESTAR II) General Electric Company, May 1986, (NEDE-2411-P-A-8-US).

14. S. Visweswaran, et al., "BWR Owners' Group Response to NRC Generic Letter 83-28, Item 4.5.3", General Electric Company, January 1985, (NEDC-30844 pages D-2 and C-3).