PDR-016

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

JAN 11 1985

Mr. Lyle Graber
Licensing Engineer
Licensing Information Service
NUS Corporation
2536 Countryside Boulevard
Clearwater, FL 33575-2094

IN RESPONSE REFER
TO FOIA-84-914

Dear Mr. Graber:

This responds to your letter dated December 7, 1984, in which you requested, pursuant to the Freedom of Information Act, that the enclosures to a September 17, 1984, memorandum from A. J. Szukiewicz to Karl Kniel regarding draft contractor reports for evaluation of a three-loop PWR be placed in the NRC Public Document Room (PDR).

We are placing copies of the following five records that you requested in the PDR.

1. EG&G Idaho, Inc., report, "Effects of Control System Failures on Transients and Accidents at a 3-Loop Westinghouse Pressurized Water Reactor Main Report," dated August 1984 (111 pages).

2. Appendices A, B, and C to the EG&G report listed in item 1, dated August 1984. (Observe that pages C-33 through C-109 of Appendix C were listed as enclosures in the September 17, 1984, Szukiewicz memorandum.)

3. August 6, 1984, notegram to John E. Hord from Stan Bruske and Clair Ransom (1 page).

4. August 10, 1984, notegram to John E. Hord from Stan Bruske and Clair Ransom (1 page).

5. September 5, 1984, notegram to Ray Calvo from Stan Bruske and Clair Ransom (3 pages).

Sincerely,

J. M. Felton, Director
Division of Rules and Records
Office of Administration

AUGUST 1984

EFFECTS OF CONTROL SYSTEM FAILURES ON TRANSIENTS AND ACCIDENTS AT A 3-LOOP WESTINGHOUSE PRESSURIZED WATER REACTOR
MAIN REPORT

NRC Licensing Support Section

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D. E. Baxter
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NRC Technical Programs Division

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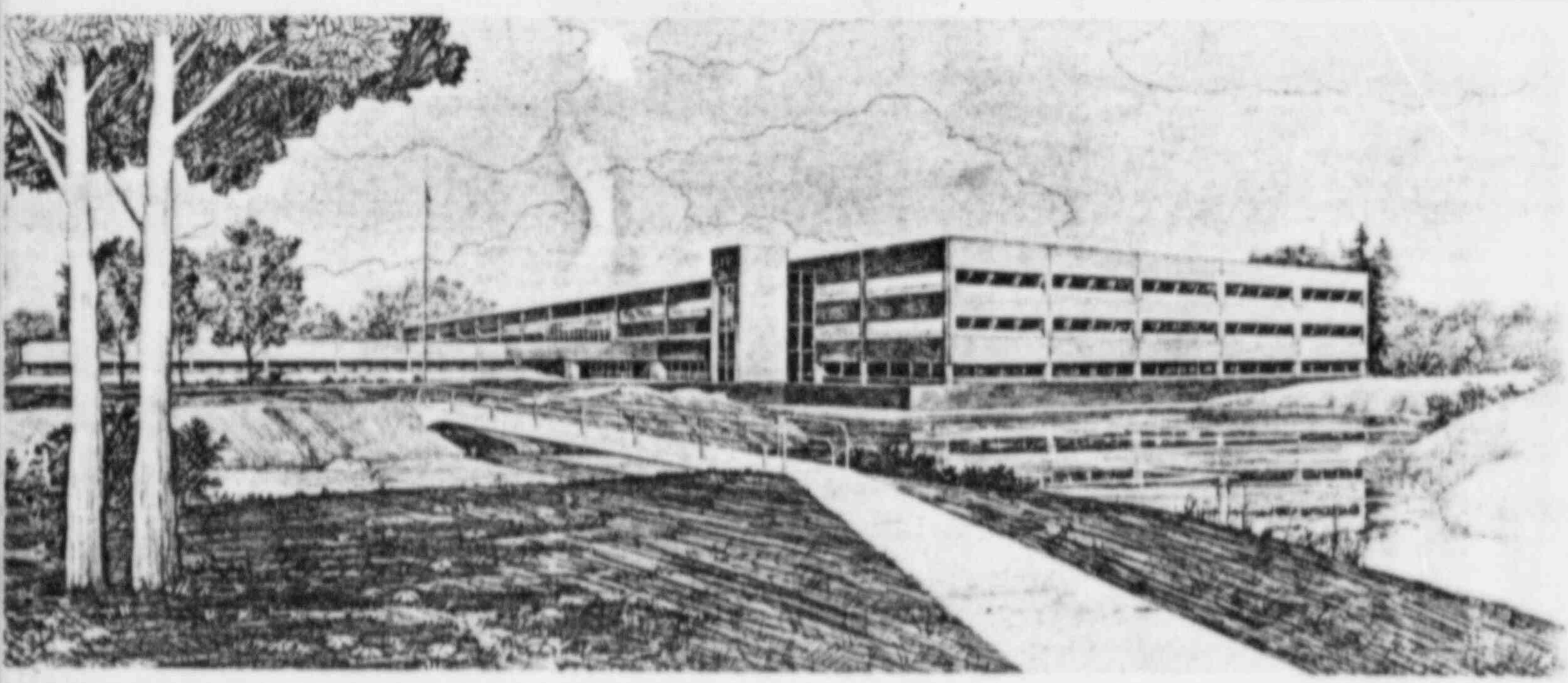
Operated by the U.S. Department of Energy



This is an informal report intended for use as a preliminary or working document

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U. S. NUCLEAR REGULATORY COMMISSION
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FIN No. A6477

EG&G Idaho

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ABSTRACT

This report documents the evaluation of the effects of nonsafety grade control system failures on a typical 3-loop Westinghouse pressurized water reactor plant.

The methods utilized for this evaluation include a system level failure modes and effects analysis, deterministic computer analysis (utilizing a plant model that includes the nuclear steam supply system, balance of plant systems and control systems), a review of 3 years of recorded plant occurrences, a probability analysis and a review of applicable Nuclear Regulatory Commission (NRC) criteria pertaining to control systems.

This study identified two system failures that could cause transients leading to a steam generator overfill and two system failures that could lead to a reactor coolant cooldown of greater than 100°F per hour. It also identified two system failures that could lead to an overpressurization at low temperatures and two steam generator tube rupture events that could be further aggravated by additional system failures.

This study concluded that the existing NRC criteria concerning control systems adequately address the potential problem areas that were identified during this evaluation. Based on the results of this study, it is recommended that the consequences and risk associated with overfill and overcool transients be further investigated. It is also recommended that the probabilites associated with the low temperature overpressurization and the steam generator tube rupture sequences be evaluated by the NRC staff.

The results of this study will be factored together with other studies being performed on the effects of control system failures to establish a position for resolution of Unresolved Safety Issue A-47 (Safety Implications of Control Systems.)

FIN A6477 - Safety Implications of Control Systems.

SUMMARY

Unresolved Safety Issue (USI) A-47 deals with the concern that accidents or transients could become more severe than previously analyzed as a result of nonsafety grade control system failures. The additional concerns dealing with nonsafety grade control system failures resulting in steam generator overfill and reactor vessel overcool transients are included as part of USI A-47.

Each of the four Nuclear Steam System Supplier (NSSS) designs are being analyzed under the A-47 Task Action Plan. This study analyzes the Westinghouse 3-loop pressurized water reactor (PWR) design based on the Carolina Power and Light H. B. Robinson Unit 2 Nuclear Plant. The goals of this study are to (1) identify the nonsafety grade control systems whose failure or misoperation can cause transients or accidents identified in Chapter 15 of the H. B. Robinson Unit 2 Steam Electric Plant Final Safety Analysis Report (FSAR) to be potentially more severe than previously analyzed or to adversely affect any assumed or anticipated operator action during the course of a particular event, and (2) establish whether control system failures or misoperation can cause unwarranted challenges to safety systems, cause Technical Specification Safety Limits to be exceeded or cause transients or accidents to occur at an unacceptable frequency.

The first step of this study was to establish a set of system selection criteria that satisfies the above stated goals. A failure mode and effects analysis (FMEA) was then performed on each plant system (as defined by the FSAR) to determine if it had the potential to meet these selection criteria. Systems that were determined to have a potential to meet these selection criteria were then analyzed to deterministically evaluate the effects of these systems failing. To aid in the deterministic analysis, a computer model was developed based on the RELAP5 computer code. The model developed for this study includes the NSSS, balance of plant (BOP) systems and control systems. RELAP5 is an advanced,

one-dimensional, thermal-hydraulic computer code with reactor kinetics and control system capabilities. This model was subjected to a verification and quality assurance review.

In addition to the results of the system failure analysis, a review of reported plant occurrences for a three year period was conducted for identification of cases where nonsafety grade control system failures had:

1. Detrimentally affected operator action,

2. Caused unwarranted challenges of safety systems,

3. Caused transients to occur at an unacceptable frequency, or

4. Caused Technical Specification Safety Limits to be exceeded.

The results of these analyses and reviews identified certain system failures that could cause transients leading to steam generator overfill, reactor vessel overcool, and reactor coolant system overpressure at low temperatures. System failures were also identified that could aggravate a steam generator tube rupture event and result in transients that are more severe than the H. B. Robinson Unit 2 FSAR steam generator tube rupture analysis. The failure sequences identified are:

1. Failures that result in increased feedwater flow rates which subsequently leads to the auxiliary feedwater flow causing a steam generator overfill.

2. Failures that result in excessive feedwater flow rates with subsequent failure of the steam generator high water level trips.

3. Failures that result in inadvertent steam dump operation with the reactor at power.

4. Failures that result in inadvertent opening of the steam line relief valves with the reactor plant in hot shutdown (T_{ave} < 547°F).

5. Failures that result in loss of letdown flow and pressure relief capabilities with the reactor plant in cold shutdown.

6. Failures that result in inadvertent safety injection (SI) initiation with the reactor plant being heated from cold shutdown with the pressurizer power operated relief valves (PORVs) set for normal full power operation.

7. Failures that result in steam line safety or relief valves failing open concurrent with a steam generator tube rupture on the affected steam generator.

8. Failures that result in steam line safety or relief valves failing open and in high feedwater flow rates concurrent with a steam generator tube rupture.

All of the other analyzed sequences were shown to be bounded by the H. B. Robinson Unit 2 FSAR analysis.

The failure mechanisms causing the above systems failures were identified and sequence probabilities were calculated. The sequence probabilities are, respectively:

Sequences	Median Value Per Reactor Year	Upper Bound Per Reactor Year
Steam Generator Overfill Sequence Number 1	1.9E-2	1.2E-1
Steam Generator Overfill Sequence Number 2	2.2E-3	1.1E-2
Reactor Coolant System Overcool Sequence Number 1	6.7E-2	2.6E-1

Sequences	Median Value Per Reactor Year	Upper Bound Per Reactor Year
Reactor Coolant System Overcool Sequence Number 2	1.6E-2	4.0E-2
Reactor Coolant System Overpressure Sequence Number 1	7.7E-7	8.2E-6
Reactor Coolant System Overpressure Sequence Number 2	8.5E-4	2.9E-3
Steam Generator Tube Rupture Sequence Number 1	2.9E-7*	3.5E-6*
Steam Generator Tube Rupture Sequence Number 2	4.3E-6*	4.8E-5*

* For the SG tube rupture events, the tube rupture is assumed to occur. The probabilities shown are for the occurrence of the aggravating failure mechanisms only.

These sequences were examined to determine if operator action could be assumed to terminate these transients. Early recognition of the transient is necessary since none of the sequences take longer than 10 minutes to exceed the applicable selection criterion. Given early recognition, there are actions that the operator could take to mitigate these transients or accidents and these operator actions are documented. However, for the purposes of this study the proposed ANSI Standard N660 was followed which assumes no operator action within the first 10 minutes. Therefore, no operator action was assumed.

The NRC criteria pertaining to control systems and accident analysis were reviewed to determine if the applicable criteria adequately addressed control system failures. Since the existing criteria addressed the identified sequences, the criteria were judged to be adequate and no revisions or additions were recommended.

The following items are recommended for NRC staff consideration.

1. This study utilized the general guidance of 10 minutes for operator action. Three of the identified sequences were assumed to occur during startup or shutdown evolutions. These evolutions are normally performed under controlled conditions; therefore, based on the available alarms, indications, and actions required, it may be judged reasonable to assume operator action in less than 10 minutes. However, this is considered a licensing decision which will require NRC staff input.

2. Since this study identified sequences which could result in steam generator overfill and reactor coolant overcool, the staff should consider initiating a study to address the consequences and risk associated with steam generator overfill and reactor coolant overcool events.

3. Two of the identified sequences are concerned with low temperature overpressurization. Overpressure Sequence 2 is assumed to occur during startup evolutions and should be considered in Recommendation 1 above. The first overpressure sequence has a calculated median probability of 7.7E-7 with an upper bound of 3.2E-6. These probabilities are considered to be very low and are several orders of magnitude less than the proposed safety goals of less than 1.0E-4. As in Recommendation 1, decisions based on probabilities are licensing decisions which will require NRC staff input.

4. The tube rupture sequences were also calculated to have a very low probability of occurence (median estimates of 2.9E-7 and 4.3E-6). These probabilities do not include the probability of a steam generator tube rupture occurring. When combined with estimates of a tube rupture occurring, these sequence probabilities are extremely low. The tube rupture sequences do, however, have the potential for direct offsite release and therefore, should be reviewed by the NRC staff.

The Westinghouse Electric Corporation, Water Reactor Division, is performing an evaluation to determine if the findings of this study are generically applicable to all Westinghouse PWRs. The Westinghouse evaluation is being performed under a separate contract with EG&G Idaho, Inc. Upon completion of the Westinghouse evaluation, that evaluation will require a review to determine if it adequatley addresses the generic aspects of this study.

Pending resolution of these items, the results of this study should be considered along with other studies being performed relating to this issue to formulate a position for resolution of Unresolved Safety Issue A-47.

FOREWORD

Safety Implications of Control Systems (A-47) was approved as an Unresolved Safety Issue (USI) by the Nuclear Regulatory Commission (NRC) in December of 1980. USI A-47 is concerned with the potential for transients or accidents being made more severe than previously analyzed as a result of control system failures. This report describes the work performed on the effects of control system failures on transients and accidents at a Westinghouse 3-loop pressurized water reactor. This work was conducted for the U. S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Division of Safety Technology by EG&G Idaho, Inc. and is based on the H. B. Robinson, Unit 2, Nuclear Plant.

This report is contained in two volumes: a main report and three appendices. The main report describes the study methodology, the major areas of work performed, and the results and conclusions. The appendices contain detailed information consisting of a detailed description of the computer model, and the deterministic computer analyses.

Numerous acronyms are used in this report. For each volume, these acronyms are defined in a listing immediately following the table of contents.

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FIGURES

TABLES

APPENDIXES

NOMENCLATURE

AEB	Accident Evaluation Branch (NRC)
AFW	Auxiliary feedwater
ATWS	Anticipated transient without scram
BOP	Balance of plant
CVCS	Chemical and volume control system
DBA	Design basis accident
ECCS	Emergency core cooling system
EHC	Electrohydraulic control
ESF	Engineered safety features
FMEA	Failure mode and effects analysis
FSAR	Final safety analysis report
ISI	In service inspection
LER	Licensee Event Report
LOCA	Loss of coolant accident
LPSI	Low pressure safety injection
LTOP	Low temperature overpressure protection
MAFW	Motor-driven auxiliary feedwater
MFW	Main feedwater
MSIV	Main steam isolation valve
NPE	Nuclear Power Experiences
NR	Narrow range
NRC	Nuclear Regulatory Commission
NSSS	Nuclear steam supply system
PORV	Power operated relief valve
PWR	Pressurized water reactor

RCP	Reactor coolant pump
RCS	Reactor coolant system
RELAP5	Reactor excursion and leak analysis program version 5 which is a deterministic thermal-hydraulic analysis computer code
RHR	Residual heat removal
RSB	Reactor Systems Branch (NRC)
SAR	Safety analysis report
SG	Steam generator
SI	Safety injection
SIAS	Safety injection actuation signal/system
SRP	Standard review plan
USI	Unresolved safety issue

EFFECTS OF CONTROL SYSTEM FAILURES ON TRANSIENTS AND ACCIDENTS AT A 3-LOOP WESTINGHOUSE PRESSURIZED WATER REACTOR

MAIN REPORT

1. INTRODUCTION

Safety Implications of Control Systems (A-47) was approved as an Unresolved Safety Issue (USI) by the Nuclear Regulatory Commission (NRC) in December 1980. This issue concerns the potential for accidents or transients being made more severe than previously analyzed as a result of control system failures. Control systems, being nonsafety grade, are only used to maintain the plant within well defined pressure and temperature limits during normal operations. These systems are not relied on to perform any safety functions during or following postulated accidents. These control systems include reactor coolant inventory controls, reactivity control, primary and secondary system pressure, flow and level controls, and associated electric, hydraulic, or pneumatic power supply systems and other plant auxiliary systems. Although it is generally believed that failures of nonsafety grade control systems are not likely to result in loss of safety functions or result in conditions that the safety systems could not mitigate, in-depth studies of the nonsafety grade systems have not been performed to verify this belief.

Each of the four Nuclear Steam System Supplier (NSSS) designs are being analyzed under the A-47 Task Action Plan. This study will analyze the Westinghouse pressurized water reactor (PWR) design based on the H. B. Robinson Steam Electric Plant, Unit 2, operated by Carolina Power and Light Company. The goals of this study are to (a) identify the nonsafety grade control systems whose failure or misoperation can cause transients or accidents identified in Chapter 15 of the H. B. Robinson Steam Electric Plant, Unit 2, Final Safety Analysis Report (FSAR)[1] to be potentially more severe than previously analyzed or adversely affect any assumed or anticipated operator action during the course of a particular event, and (b) establish whether control system failures or misoperation can cause unwarranted challenges to safety systems, cause Technical Specification Safety Limits to be exceeded or cause transients or accidents to occur at

an unacceptable frequency. The purpose of this study is to verify the adequacy of current NRC licensing design requirements, and if necessary, to propose additional guidelines or criteria that would help assure that nuclear power plants do not pose an unacceptable risk to the public due to nonsafety grade control system failures.

The basic steps used to perform this work are discussed below and are shown in Figure 1. The initial step was to establish a set of system Selection Criteria that satisfy the above stated goals. A failure mode and effects analysis (FMEA) was then performed on each plant system (as defined by the FSAR) to determine if it had the potential to meet these criteria. A failure mode, for this study, is the means by which a system fails to perform its intended function. Mechanistic failures (components that cause the system failure mode) are analyzed later in the study.

The computer model used to analyze the systems that had the potential to meet the Selection Criteria was developed in parallel with the above activities. The computer model was based on RELAP5[2] which is an advanced, one-dimensional, thermal-hydraulic code with reactor kinetics and control system capabilities. This model was subjected to a verification and quality assurance review.

The results of the computer analysis identify the means by which the effects of the system failure was mitigated. If the means of mitigation was a nonsafety grade system, that system or component was also failed in a second computer analysis. This iterative process led to the development of scenarios from which significant system failures could be determined. In addition to the results of the computer analysis, component failure data bases such as Licensee Event Reports (LERS) were examined for identification of cases where control system failures: (a) affected operator action, (b) caused challenges to Engineered Safeguard Systems, (c) resulted in exceeding Technical Specification Safety Limits, and (d) caused transients to occur at an unacceptable frequency. The significant

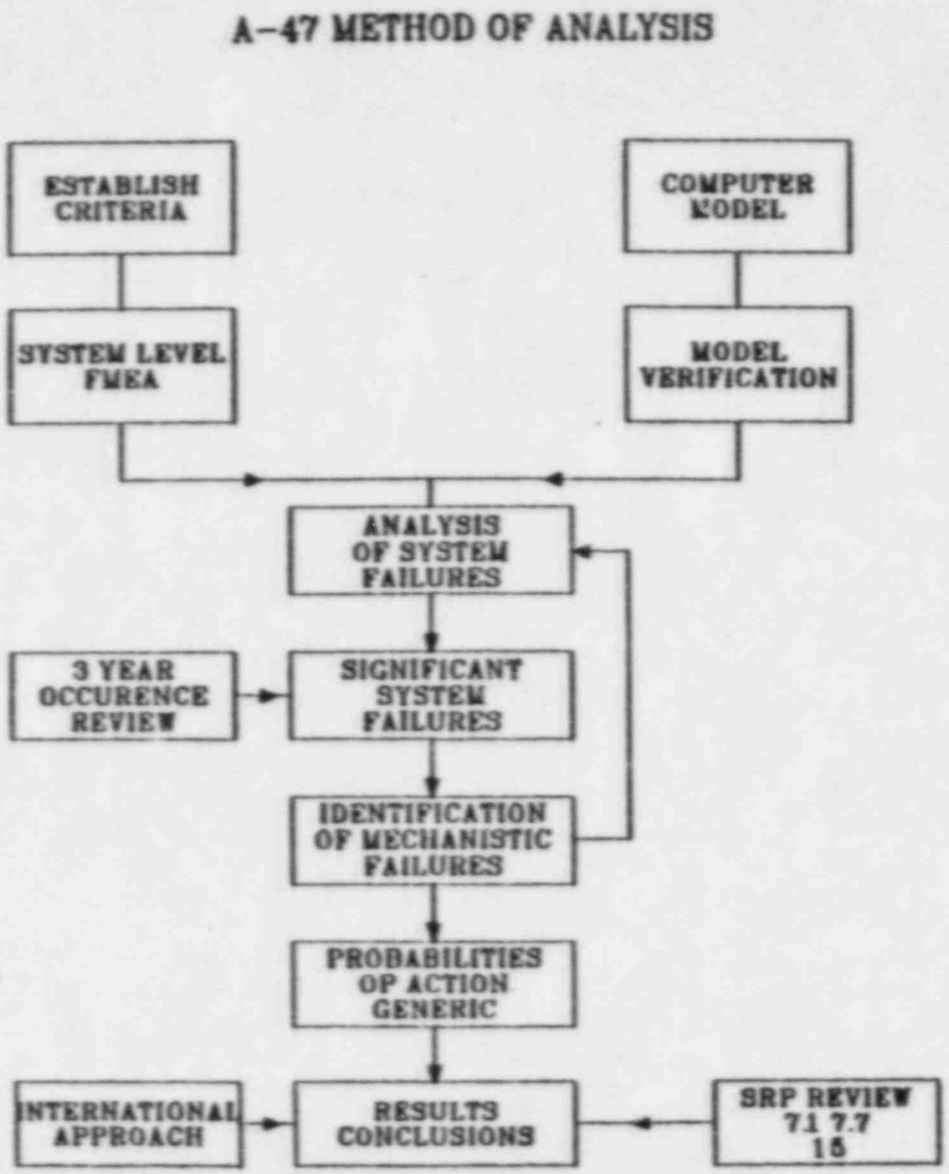

Figure 1. Study methodology flow chart.

systems were reviewed for identificaton of the mechanistic failures. Once the mechanistic failures were identified, a probabilistic analysis was performed to estimate the frequency of the scenarios.

After the scenarios were identified, the following evaluations were made: (a) potential operator actions to mitigate the effects of the failures; (b) whether or not these plant specific scenarios could be extended to Westinghouse PWR plants in general; and (c) to verify the adequacy of the NRC's licensing requirements (Standard Review Plan Sections, 7.1, 7.7, 15) and, if necessary, to propose additional guidelines and criteria that would assure that nuclear power plants do not pose an unacceptable risk due to nonsafety grade control systems.[3] The conclusions and results were based on the findings of this study and of a review of the practices the international nuclear community takes with regard to nonsafety grade system interaction with safety systems.

2. TECHNICAL APPROACH

The following sections describe the technical approach used in this study and includes the Selection Criteria, the FMEA, the failure data base search, the computer model description, the event scenario computer analysis and effects, the mechanistic failure analysis, and the sequence probability analysis.

2.1 Significant System Selection Criteria

The purpose of the Selection Criteria is to provide a basis to meet the goals of this study. The goals of this study are (a) to identify the nonsafety grade control systems whose failure or misoperation can cause, contribute to, or aggravate transients or accidents identified in Chapter 15 of the H. B. Robinson Steam Electric Plant FSAR to be made potentially more severe than previously analyzed or create the potential to adversely affect any assumed or anticipated operator action during the course of a particular event, and (b) to establish whether control system failures or misoperation can cause unwarranted challenges to safety systems, cause Technical Specification Safety Limits to be exceeded, or cause transients or accidents to occur at an unacceptable frequency.

Several sources of information were used to develop the Selection Criteria that meet the above stated goals. The first step was to identify the type of transients and accidents that need to be considered in the FSAR. Chapter 15 of Regulatory Guide 1.70[4] identifies the transient and accident categories (events) that should be addressed in the FSAR. The events chosen from Regulatory Guide 1.70 are:

1. Increase in heat removal by the secondary system.

2. Decrease in heat removal by the secondary system.

3. Decrease in reactor coolant system flowrate.

4. Reactivity and power distribution anomalies.

5. Increase in reactor coolant inventory.

6. Decrease in reactor coolant inventory.

There are two additional events identified in Regulatory Guide 1.70 that were not used in the development of the Selection Criteria. One event covers failure of radioactive liquid tanks outside containment and fuel handling accidents. This event was excluded from the Selection Criteria since radioactive liquid tanks outside containment do not interface with control systems used during normal plant operations and fuel handling activities do not take place during normal plant operations. The other event covers anticipated transients without scram (ATWS). ATWS events are beyond the scope of this study.

Steam generator overfill, which would normally be a part of the increase in heat removal by the secondary system event, and steam generator tube rupture, which would normally be a part of the decrease in reactor coolant inventory event, were treated in this study as additional events of concern. Even though steam generator overfill and steam generator tube rupture will contribute to their parent events (increase in heat removal by the secondary system and decrease in reactor coolant inventory, respectively), there are specific concerns associated with the steam generator overfill and the steam generator tube rupture that are not critical concerns for the parent event. For example, the specific concerns for steam generator overfill include static loading of the steam line piping, water slug and water hammer loadings, and the possibility that safety related equipment, such as the safety relief valves and the turbine driven auxiliary feedwater pump(s) which interface with the main steam system, may be damaged or fail to perform their intended functions under steam generator overfill conditions. These specific concerns are also applicable to a steam generator tube rupture since a steam generator tube rupture can lead to steam generator overfill. Thus, on the basis of these specific concerns, steam generator overfill and steam generator tube rupture were considered important enough to warrant treating them as additional events.

Regulatory Guide 1.70 also identifies the frequency classifications. The frequency classifications are incidents of moderate frequency, infrequent incidents, and limiting faults. Incidents of moderate frequency are any incidents that may occur during a calendar year. Infrequent incidents are any incidents that may occur during the lifetime of a plant. Limiting faults, which are also referred to as design basis accidents (DBAs), are incidents that are not expected to occur during the lifetime of a plant but are postulated because their consequences would include the potential for the release of significant amounts of radioactive material. A Selection Criterion was developed to address exceeding these frequency classifications.

Once the events and frequency classifications were identified, it was possible to start developing some of the Selection Criteria. For example, the draft version of the overfill criterion becomes: any control grade system or component failure, either initiating or aggravating, which results in an undesired increase in steam generator water level to the point of overfill. The point of overfill is defined as that level, which if exceeded, could cause carryover into the turbine and subsequent damage (> 75% of indicated level). In this particular case it was acknowledged that an overfill in excess of the high level trip setpoint posed no safety implications until moisture entered the main steam line. Thus, the final version of the overfill criterion is: any control grade system or component failure, either initiating or aggravating, which results in an undesired increase in steam generator water level to the point where moisture enters the main steam lines will be recommended for further review. For this study, the point of overfill is defined as that level which, if exceeded, could cause carryover into the main steam system. To complete the criterion, Chapter 15 of the H. B. Robinson Unit 2 FSAR was used to identify the applicable limiting transient and the design basis accident. Identification of the limiting transient and the design basis accident provides the basis to determine if control system failures can result in transients or accidents being more severe than previously analyzed in the H. B. Robinson Unit 2 FSAR. The Selection Criteria for the remaining events listed above (Increase in Reactor Coolant Inventory, etc.) were developed in the same manner. The first eight Selection Criteria,

presented in Table 1, correspond to the first part of the first goal dealing with the capability to identify the control systems whose failure or misoperations can cause, contribute to, or aggravate transients or accidents in Chapter 15 of the H. B. Robinson Unit 2 FSAR to be made potentially more severe than previously analyzed.

Also, once the frequency classifications were identified, the ninth Selection Criterion could be developed. The ninth criterion corresponds to that part of the second goal dealing with establishing whether control system failures or misoperation can cause transients or accidents to occur at an unacceptable frequency.

The remaining parts of the goals not yet covered are whether control system failures can create the potential to adversely affect any assumed or anticipated operator action during the course of a particular event, cause unwarranted challenges to safety systems, or cause Technical Specification Safety Limits to be exceeded. The last criterion was developed to address these items. The H. B. Robinson Technical Specifications document was used to identify the Technical Specification Safety Limits. The complete Selection Criteria are presented in Table 1.

To summarize, all of the Selection Criteria correspond to the goals of this study. The fist eight criteria are based on Regulatory Guide 1.70, Task Action Plan A-47 and Chapter 15 of the H. B. Robinson Unit 2 FSAR. The ninth criterion is based on Regulatory Guide 1.70. The tenth criterion is based on the H. B. Robinson Technical Specification Safety Limits and on the additional concerns of control system failures causing unwarranted challenges to safety systems or adversely affecting operator actions or the operation of automatic protection systems during the course of a particular event.

TABLE 1. SYSTEMS SELECTION CRITERIA

1. Any control grade system or component failure, either initiating or aggravating, that results in an undesired reactor coolant water temperature decrease beyond the bounds of the present FSAR analysis will be recommended for further review.

   The limiting transient analysis in the H. B. Robinson FSAR for this overcooling event is the "decrease in feedwater temperature."

   The design basis accident for this overcooling event is the "large steam line break outside of containment with offsite power available," even though it meets all of the requirements of a bounding transient.

2. Any control grade system or component failure, either initiating or aggravating, that results in an undesired nuclear system pressure increase beyond the bounds of the H. B. Robinson FSAR analysis will be recommended for further review.

   The limiting transient for a nuclear system pressure increase event in the H. B. Robinson FSAR analysis is the "instantaneous loss of steam load (turbine trip) without automatic steam dump or reactor trip."

   There is no design basis accident identified for the decrease in heat removal by the secondary system (increasing nuclear system pressure) event.

3. Any control grade system or component failure, either initiating or aggravating, that results in an undesired positive reactivity increase beyond the bounds of the H. B. Robinson FSAR analysis will be recommended for further review.

   The limiting transient for a positive reactivity increase event is the "uncontrolled rod control cluster assembly (RCCA) bank withdrawal from full power with minimum reactivity feedback (80 pcm/s withdrawal rate)."

   The design basis accident for the increase in positive reactivity event is "rod control cluster assembly (RCCA) ejection near the end of life of the core."

4. Any control grade system or component failure, either initiating or aggravating, that results in an undesired increase in reactor coolant inventory beyond the bounds of the H. B. Robinson FSAR analysis will be recommended for further review.

TABLE 1. (continued)

The limiting transient for an increase in reactor coolant inventory is "inadvertent start of a safety injection (SI) pump with the plant in a cold shutdown condition."

There is no design basis accident identified for the increase reactor coolant inventory event.

5. Any control grade system or component failure, either initiating or aggravating, that results in an undesired reactor core coolant flow decrease beyond the bounds of the H. B. Robinson FSAR analysis will be recommended for further review.

   The limiting transient for a decrease in reactor coolant flow is "a simultaneous loss of power to all reactor coolant pumps at full power."

   The design basis accident for the decrease in reactor coolant flow is the "instantaneous shaft seizure (locked rotor) of the reactor coolant pumps."

6. Any control grade system or component failure, either initiating or aggravating, that results in a reactor vessel inventory decrease beyond the bounds of the H. B. Robinson FSAR analysis will be recommended for further review.

   The limiting transient for the decrease in reactor coolant inventory is considered to be the "steam generator tube rupture at full power." (Based on offsite release.)

   The design basis accident for this event is the "double-ended cold leg guillotine (DECLG) pipe break."

7. Any control grade system or component failure, either initiating or aggravating, that results in an undesired increase in steam generator water level to the point where moisture enters the main steam line will be recommended for further review. For this study, the point of overfill is defined as that level which, if exceeded, could cause carryover into the main steam system.

   The limiting transient in the H. B. Robinson FSAR for the steam generator overfill event is considered to be "feedwater system malfunctions that result in an increase in feedwater flow."

   There is no design basis accident identified in the H. B. Robinson FSAR for the steam generator overfill event.

TABLE 1. (continued)

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8. Any control grade system or component failure, either initiating or aggravating, that results in a steam generator tube rupture causing a release of radioactive material to the atmosphere greater than the FSAR analysis calculated.

9. Any control grade system or component failures that are projected to cause transients identified as incidents of moderate frequency (Anticipated Operational Occurrences) to occur at a rate significantly more frequent than once a year, or failures which are projected to cause transients identified as infrequent incidents to occur more than once during the lifetime of a plant, or failures which are projected to cause limiting faults (Design Basis Accidents) will be recommended for further review.

10. Any control grade system or component failures that would adversely affect any assumed or anticipated operator action during the course of a particular event, or result in manual or automatic actuation of Engineered Safety Features, including the Reactor Protection System, or result in exceeding any Technical Specification Safety Limit will be recommended for further review.

2.2 Failure Mode and Effects Analysis

A failure mode and effects analysis (FMEA) was used in this study as a screening method to determine if a nonsafety grade control system has the potential to cause accidents or transients to be more severe than previously analyzed in H. B. Robinson Unit 2 Steam Electric Plant Final Safety Analysis Report (FSAR). An FMEA is a method by which a failure mode is assumed to have occurred and the effect of this failure examined. Since the effects of nonsafety grade control system failures are of primary interest for this study, the failure modes of interest would normally be at the control system level. That is, failure of control systems to perform their intended functions such as to control pump speed, valve position, reactivity, etc. Because of the numerous failure possibilities, a screening method was first used by defining the failure mode as total system failure instead of control system failure. Then a worst case analysis was conducted by failing the system to extreme operational conditions such as full flow or no flow, etc., and if the system had no de rimental influence on the event of concern then it was not necessary to analyze its various control systems. In addition, it was decided to analyze safety grade systems as well as nonsafety grade systems in order to verify compliance with Appendix B to Standard Review Plan Section 7.1 which covers conformance to IEEE Standard 279[6]. The effects of a system failure were analyzed against eight event categories which correspond to the first eight Selection Criteria. The eight event categories were obtained from Regulatory Guide 1.70, A-47 Task Action Plan and Chapter 15 of the H. B. Robinson Unit 2 FSAR. The eight events chosen were:

1. Increase in heat removal by the secondary system.

2. Decrease in heat removal by the secondary system.

3. Reactivity and power distribution anomalies.

4. Increase in reactor coolant inventory.

5. Decrease in reactor coolant system flow rate.

6. Decrease in reactor coolant inventory.

7. Steam generator overfill.

8. Steam generator tube rupture.

All of the systems defined in the H. B. Robinson Unit 2 FSAR were analyzed in this study. An FMEA[7,8,9] was performed on all of the systems for each event of concern and the results of the FMEA are presented in Table 2.

A deterministic analysis was then performed on systems that were found to be suspect to determine the magnitude of failure effect. The number of suspect systems for each event analyzed is shown in Table 2. These systems and applicable failure modes were then subjected to deterministic computer analyses (see Section 2.5) to make a final determination as to whether the system failure mode could result in making the applicable transient or accident for the particular event of concern more severe than previously analyzed in the H. B. Robinson Unit 2 FSAR.

2.3 Failure Data Base Search

A search of Licensee Event Report (LERs) and Nuclear Plant Experience (NPE) data bases for H. B. Robinson Unit 2 from January 1980 to December 1982 were reviewed to determine if control system failures:

1. caused transients or accidents to occur more frequently than anticipated,

2. detrimentally affected operator action,

TABLE 2. SELECTED SYSTEMS FOR EVENTS OF CONCERN

Event of Concern	Suspected System and Failure Modes
1. Reactor Coolant Overcool	A. Reactor Coolant System and Pumps--Inadvertent start
	B. Pressurizer Overpressure Protection System--Inadvertent opening
	C. Safety Injection System--Inadvertent start
	D. Residual Heat Removal System--Inadvertent start
	E. Chemical and Volume Control System--High makeup flow and/or low letdown flow
	F. Reactor Protection System--Inadvertent reactor trip
	G. Control Rod Drive System--Inadvertent insertion or dropped rod
	H. Feedwater and Condensate System-High feed flowrate of feedwater heating fails
	I. Steamline Overpressure Protection System--Inadvertent PORV or safety valve opening
	J. Main Steam System--Inadvertent MSIV opening
	K. Turbine Generator System--Inadvertent turbine control valve opening
	L. Auxiliary Feedwater System--Inadvertent start
	M. Steam Generator--Tube rupture
	N. Steam Generator Blowdown System--High flowrate
	O. Auxiliary Steam System--High flowrate
	P. Main Condenser, Evacuation, and Circulating Water Systems--Increased vacuum or high circulating water flow
	Q. Steam Dump System--Inadvertent valve opening
	R. Component Cooling Water System--High flowrate
2. Increase in Reactor Pressure	A. Reactor Coolant System and Pumps--Decreased flow
	B. High Head Safety Injection System--Inadvertent start
	C. Residual Heat Removal System--Inadvertent start or low flow
	D. Chemical and Volume Control System--High makeup and/or low letdown flow
	E. Pressurizer Pressure Control System--Controlling pressure high
	F. Accumulator Tank System--Inadvertent injection
	G. Control Rod Drive System--Rod withdrawal or ejection
	H. Feedwater and Condensate Systems--No flow
	I. Main Steam System--No steam flow
	J. Steam Generator--Fails to transfer heat
	K. Turbine Generator Systems--Inadvertent control valve closure
	L. Auxiliary Steam--No flow
	M. Main Condenser, Evacuation, and Circulating Water Systems--Loss of vacuum or no circulating water flow
	N. Steam Dump System--Fails to operate
3. Positive Reactivity Increase	A. Reactor Coolant System and Pumps--Inadvertent start
	B. Chemical and Volume Control System--Add nonborated water
	C. Control Rod Drive System--Inadvertent withdrawal or ejection
	D. Feedwater and Condensate Systems--High flowrate and/or loss of heating

TABLE 2. (continued)

Event of Concern	Suspected System and Failure Modes
3. Positive Reactivity Increase (continued)	E. Steamline Overpressure Protection System--Inadvertent PORV or safety valve opening
	F. Main Steam System--Inadvertent MSIV opening
	G. Turbine Generator System--Inadvertent control valve opening
	H. Auxiliary Feedwater System--Inadvertent start
	I. Steam Generator Blowdown System--High flowrate
	J. Auxiliary Steam System--Increased flow
	K. Main Condenser, Evacuation, and Circulating Water Systems--Increased vacuum or circulating water flow
	L. Steam Dump System--Inadvertent valve opening
4. Increase in Reactor Coolant System Inventory	A. High Head Safety Injection System--Inadvertent start
	B. Residual Heat Removal System--Inadvertent start
	C. Chemical and Volume Control System--High makeup and/or reduced letdown flow
	D. Accumulator Tank System--Inadvertent injection
5. Decrease in RCS Flow	A. Reactor Coolant System and Pumps--No flow
	B. Residual Heat Removal System--No flow
6. Decrease in RCS Inventory	A. Reactor Coolant System and Pumps--No flow which increases pressure
	B. Pressurizer Overpressure Protection System--Inadvertent PORV or safety valve opening
	C. Residual Heat Removal System--No flow
	D. Chemical and Volume Control System--No charging flow or high letdown flow
	E. Pressurizer Pressure Control System--Pressure controlled high
	F. Control Rod Drive System--Rod ejection
	G. Main Steam System--Inadvertent MSIV closure
	H. Turbine Generator System--Inadvertent control valve closure
	I. Steam Dump System--Inadvertent valve closure
	J. Steam Generator--Tube rupture
	K. Main Condenser, Evacuation, and Circulating Water Systems--Loss of vacuum or no circulating water flow
7. Steam Generator Overfill	A. Control Rod Drive System--Withdrawal or ejection of rods
	B. Feedwater and Condensate System--High flowrate
	C. Steam Line Overpressure Protection System--Inadvertent opening of a PORV or safety valve
	D. Main Steam System--High flowrate or inadvertent MSIV opening
	E. Turbine Generator System--Inadvertent valve opening
	F. Auxiliary Feedwater System--Inadvertent start
	G. Steam Generator--Tube rupture
	H. Steam Generator Blowdown--Low flowrate
	I. Auxiliary Steam System--High flowrate
	J. Main Condenser, Evacuation, and Circulating Water Systems--Increased vacuum or high circulating water flow
	K. Steam Dump System--Inadvertent opening or high flowrate

TABLE 2. (continued)

Event of Concern		Suspected System and Failure Modes
8. Steam Generator Tube Rupture	A.	Reactor Coolant System and Pumps--No flow
	B.	Chemical and Volume Control System--High charging flow and no letdown flow
	C.	Pressurizer Pressure Control System--Pressure being controlled high
	D.	Control Rod Drive System--Uncontrolled rod withdrawal
	E.	Feedwater and Condensate System--No flow or high flow to the affected steam generator
	F.	Steamline Overpressure Protection System--Inadvertent PORV or safety valve operation
	G.	Main Steam System--Inadvertent opening or failure to close an MSIV on the affected SG, and inadvertent closure of an MSIV on a nonaffected steam generator
	H.	Turbine Generator Systems--Inadvertent control valve closure
	I.	Auxiliary Feedwater System--Inadvertent start
	J.	Steam Generator--Tube rupture
	K.	Steam Generator Blowdown System--High flow
	L.	Steam Generator Sampling System--High flow
	M.	Auxiliary Steam System--No flow
	N.	Main Condenser, Evacuation, and Circulating Water Systems--Loss of vacuum or no circulating water flow
	O.	Steam Dump System--Fails to operate

3. resulted in Engineered Safeguards Features actuation, or

4. exceeded Technical Specifications Safety Limits.

These data bases were reviewed since the above concerns could not be addressed by an FMEA or computer analysis.

The potentially significant events that were noted are: Reactor protection relays failing to reenergize, steam generator water level indicator failure, premature breaker trip causing loss of power to essential equipment, auxiliary feedwater pump trip due to steam binding, reactor coolant pump diffuser adapter bolt failures, main steam line isolation check valve failure due to loose setscrews, and steam generator tube leaks from failed tubes and plug leaks.

Although these events had transient potential, they did not result in transients or occur at a frequency in excess of those for anticipated operational occurrences. With the exception of tube leaks discovered during operation, all of the failures were identified during periodic testing or inservice inspection (ISI) of plant systems and components.

To identify control system failures that could adversely affect operator action, a review was performed of the operational events that involved failure of an indication and/or alarm system. None of these events produced any cases where the operators took actions that were detrimental to the plant or the equipment based on the incorrect alarms or indication.

The events were also reviewed for control system failures that resulted in actuation of Engineered Safety Feature (ESF) systems. There were no control system failures identified during the review period that caused the actuation of any ESF system.

There were no control system failures identified during the review period that resulted in actuation of the reactor protection system or that resulted in exceeding a Technical Specification Safety Limit.

The conclusions are that this review of the failure experiences at H. B. Robinson Unit 2 during the time period of January 1, 1980 through December 31, 1982, identified no control system failures that resulted in transients occurring at a high frequency, affected operator action, resulted in actuation of ESF or the reactor protection system, or violated a Technical Specification Safety Limit.

2.4 Computer Model Description

A RELAP5/MOD1.5[2] model of the H. B. Robinson Unit 2 (HBR-2) plant was used to perform a deterministic analysis of the effects of failing the systems and components found suspect in the FMEA.

This model consisted of: (a) the pressure vessel, (b) the three primary coolant loops, (c) the three steam generators, (d) the main feedwater system, (e) the auxiliary feedwater system (modeled as a boundary condition), (f) the steam lines, header, and turbine first stage volume, and (g) the plant control systems and associated protective trip logic.

A detailed description of the computer model is presented in Appendix B. The results of the computer analysis are discussed in Section 2.5 and in Appendix C.

2.5 Event Scenario Computer Analysis and Effects

The purpose of the event scenario development process and the computer analysis is to develop postulated scenarios in a logical manner and deterministically examine these postulated scenarios using the computer code described in Section 2.4 to determine if these postulated scenarios result in transients or accidents that are more severe that previously analyzed in Chapter 15 of the H. B. Robinson Steam Electric Plant, Unit 2, FSAR. The logical development of the postulated scenarios considers the

selected suspect systems identified in Section 2.2 (see Table 2). The deterministic analysis will show if any of the first eight Selection Criteria, presented in Section 2.1 (see Table 1), are exceeded.

The event scenario development and deterministic analysis process consists of the following steps:

1. For each event of concern (steam generator overfill, reactor coolant overcool, etc.) the limiting transient and the DBA, as presented in Chapter 15 of the H. B. Robinson, Unit 2 FSAR, were deterministically analyzed as necessary. These deterministic analyses on the limiting transient and the DBA are referred to as the baseline scenarios (baseline steam generator overfill scenario, baseline reactor coolant overcool scenario, etc).

2. If nonsafety grade systems were utilized in mitigating the baseline scenario, failure of the nonsafety grade systems were postulated for the next scenario that was deterministically analyzed. Thus, this step identified potential failures of nonsafety grade systems and determined if the applicable Selection Criteria were exceeded.

3. Next the baseline scenario was examined to determine if a single safety grade system failure was assumed. If not, the applicable safety grade systems from the selected suspect systems list (see Section 2.2, Table 2) were examined to determine which single safety grade system failure would produce the worst case transient or accident plant conditions for each event of concern. In some cases, it was not possible to determine which single safety grade system failure would produce the worst case transient or accident conditions; thus, it was necessary to perform a sensitivity analysis by deterministically analyzing several single safety grade system failures individually. Thus, this step identified potential single safety grade system failures and determined if the applicable Selection Criteria were exceeded.

4. In this step, an engineering evaluation of the H. B. Robinson, Unit 2 FSAR initial plant conditions assumed for the baseline scenario was performed to identify which initial plant conditions (power, flow, etc.) could have the most significant effect on the baseline scenario. The purpose of this step was to verify or establish as necessary the worst case initial plant conditions. In some cases it was not possible to determine which one initial plant condition (reactor parameter such as power, flow, etc.) influenced the outcome of the baseline scenario the most, thus, as necessary, a sensitivity analysis was performed by varying reactor parameters and performing individual deterministic analysis.

5. The purpose of this step was to identify system failures from the selected suspect system list that would aggravate the baseline scenario the most or in other words, produce the worse-case aggravated scenario that exceeded the Selection Criteria. As in the previous two steps, it was not always possible to determine which selected suspect systems would produce the worse-case aggravated scenario; thus, as necessary, deterministic analyses were performed.

6. Systems identified as dependent on electrical power or air were deterministically analyzed next, as necessary, to determine if the Selection Criteria would be exceeded if these systems failed due to loss of electrical power or air.

From this event scenario development and analysis process, scenarios were identified that exceeded the Selection Criteria. For the remainder of this report (except Appendix C), the scenarios that exceed the Selection Criteria will be referred to as sequences to distinguish them from the scenarios that did not exceed the Selection Criteria. All of the scenarios that were developed and deterministically analyzed are presented in Appendix C.

Eight sequences were identified that exceeded one or more of the Selection Criteria. These sequences are listed below with their failure modes and the Selection Criteria that were exceeded.

1. Reactor Coolant System Overcool Sequence Number 1--inadvertent opening of the steam dump valves at 102% power, exceeds Selection Criterion 1.

2. Reactor Coolant System Overcool Sequence Number 2--inadvertent opening of the steamline PORVs at hot shutdown, exceeds Selection Criterion 1.

3. Reactor Coolant System Overpressure Sequence Number 1--mismatch between charging flow and letdown flow coincident with pressurizer PORV failure at cold shutdown, exceeds Selection Criterion 2.

4. Reactor Coolant System Overpressure Sequence Number 2--inadvertent initiation of high head SI and accumulators during heatup or cooldown with the reactor shutdown after the pressurizer PORV setpoint has been returned to the normal operations setpoint, exceeds Selection Criterion 2.

5. Steam Generator Overfill Sequence Number 1--increase in feedwater flow during low power operations, exceeds Selection Criterion 7.

6. Steam Generator Overfill Sequence Number 2--increase in feedwater flow and a failure of the high steam generator trip, exceeds Selection Criterion 7.

7. Steam Generator Tube Rupture Sequence Number 1--a tube rupture occurs and is aggravated by a loss of off-site power and a failure open of a steamline PORV or safety valve, exceeds Selection Criteria 1, 7, and 8.

8. Steam Generator Tube Rupture Sequence Number 2--a tube rupture occurs and is aggravated by a increase in feedwater flow and a failure open of a steamline PORV or safety valve, the calculation was terminated on this sequence prior to exceeding any of the selection criteria; however, by extroplation of the data Selection Criteria 1, 7, and 8 would be exceeded by this sequence.

The sequences that were found to exceed a selection criteria are described in greater detail in the following sections.

2.5.1 Reactor Coolant System Overcool Sequence Number 1

The initial plant conditions for Reactor Coolant System Overcool Sequence Number 1 are the plant at 102% reactor power and all control systems in automatic. The sequence is initiated by failing the steam dump valves to their open position. This failure creates an increase in steam flow which reduces secondary pressure and causes a pressure surge back into the feed system that trips a main feedwater pump on low feedline pressure. This leads to a turbine trip, a reactor trip, and closure of the turbine stop valve. The high initial power level was assumed in order to place the plant closer to the setpoints that actuate a reactor trip. As was shown by the analyses of scenarios where the turbine control valve was assumed to fail open, unless a reactor trip is actuated, the plant will not overcool. The steam dump valves opening provided the pressure transient that ultimately led to a reactor trip and also provided the cooldown mechanism after the trip by removing more energy than is produced as decay heat in the reactor.

The additional failures assumed for this sequence had no effect on the analysis since both were circumvented by the resulting sequence of events as shown in Table 3. The first aggravating failure involved disabling the turbine trip that is actuated by a reactor trip and the second was to set the high power level trip point to the low end of the permissible range.

The steam flow out of the steam dumps, shown in Figure 2, went to 500 kg/s (1102 lbm/s) when the valves were initially opened. This flowrate gradually dropped for 75 s, at which time it began a more rapid decrease as it followed secondary pressure down. Secondary pressure (Figure 3) was responding to the falling reactor coolant system (RCS) temperature as shown in Figure 4.

The rapid RCS cooldown due to more energy being removed than was being added (Figure 5), resulted in a decrease in primary pressure (Figure 6) and an outflow from the pressurizer. The low pressure setpoint was reached in 5 s, and 40 s later, the low pressurizer level trip resulted in the pressurizer heaters being deenergized. RCS pressure and pressurizer level continued to decrease due to the RCS cooldown, and at 90 s after initiation of the transient the pressurizer emptied, as shown in Figure 7. Voids began to form in the reactor upper plenum (Figure 8) 5 s later which retarded the pressure decrease as the RCS pressure was now at the saturation point for the upper plenum temperature. At this point high head SI flow was initiated into the RCS, as shown in Figure 9, and it continued until the calculation was terminated at 240 s.

A vapor bubble began forming in the reactor upper head (Figure 10) at 110 s and it continued to expand for the duration of the calculation. As the temperature decreased in the upper plenum, the void shifted from the plenum to the upper head.

During the 240 s of this calculation the RCS temperature (T_{ave}) decreased approximately 143°F, which exceeds Selection Criterion 1. Therefore, this deterministic analysis demonstrates that a failure of the steam dump system can result in an RCS overcool event.

2.5.2 Reactor Coolant System Overcool Sequence Number 2

The initial plant conditions for this sequence are the reactor in a hot shutdown condition with the reactor coolant pumps operating and a RCS temperature of 547°F. Rod control, pressure control, and feedwater control

TABLE 3. SEQUENCE OF EVENTS FOR REACTOR COOLANT SYSTEM OVERCOOL SEQUENCE NUMBER 1

Time (s)	Event
0.0	Steam dump valves opened.
2.1	Main feedwater pump tripped on low feedline pressure. Turbine tripped, reactor tripped, and turbine stop valve closed.
5.0	Low RCS pressure.
45.0	Low pressurizer level, pressurizer heaters tripped off.
90.0	Pressurizer emptied.
95.0	Void started to form in upper plenum.
110.0	Void started to form in reactor upper head region, void from upper plenum began to transfer to the upper head region.
240.0	End of calculation.

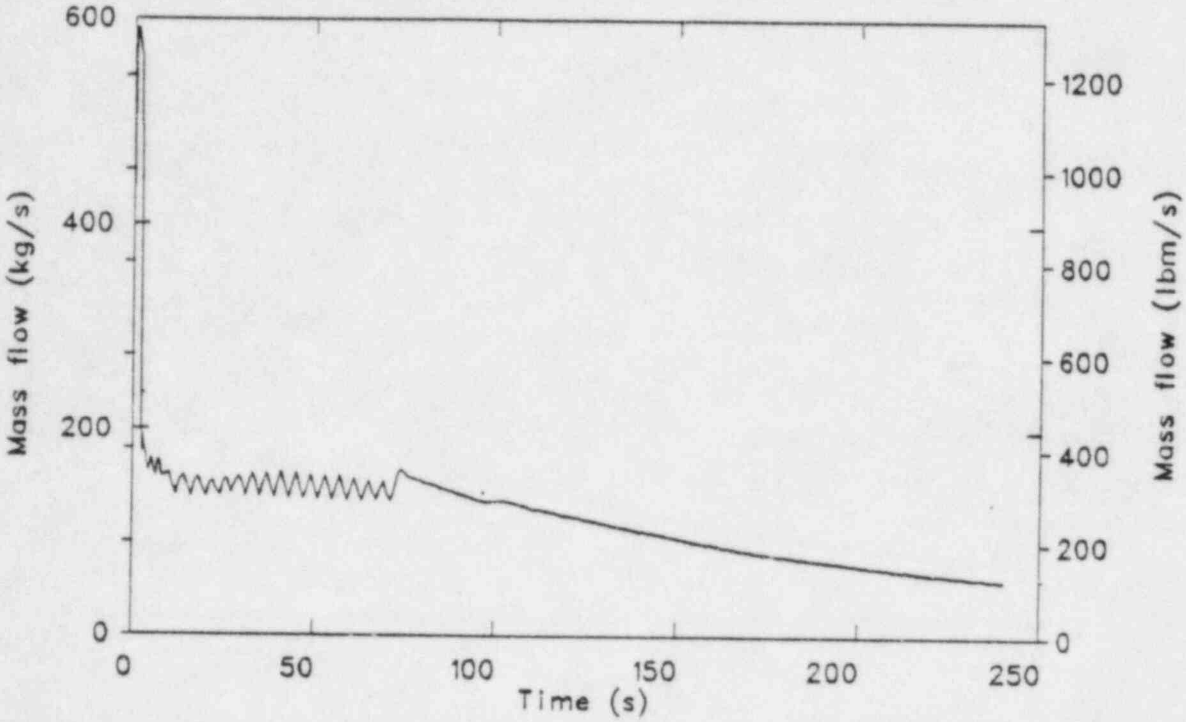

Figure 2. Steam dump flow for Reactor Coolant System Overcool Sequence Number 1.

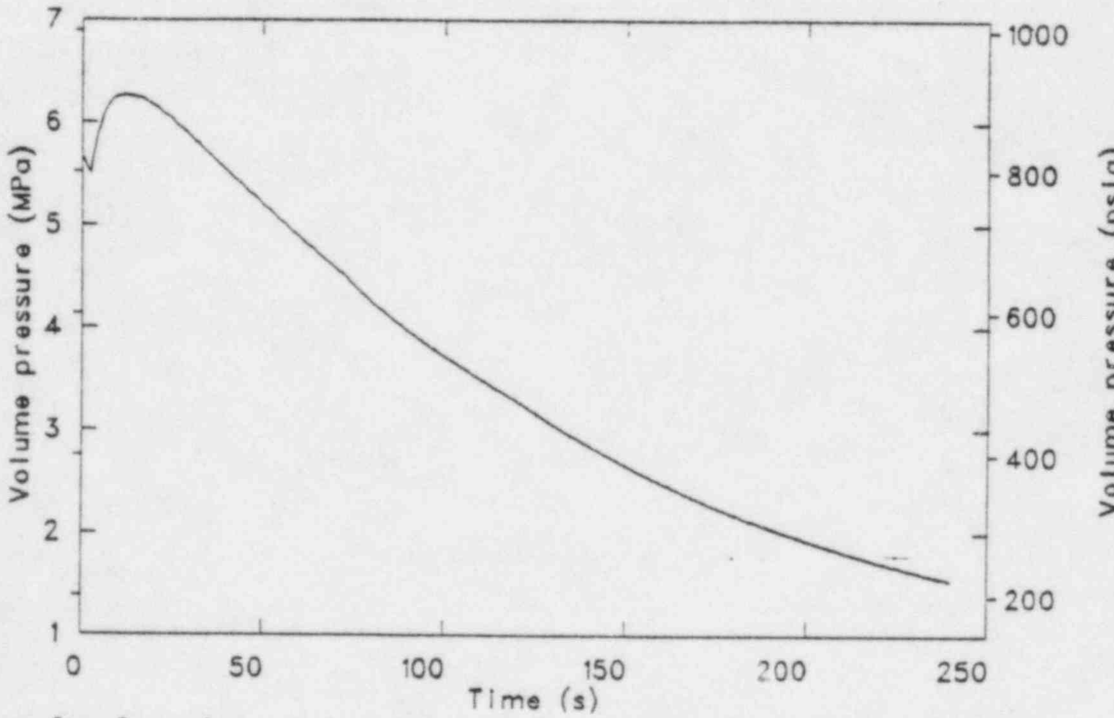

Figure 3. Secondary system pressure for Reactor Coolant System Overcool Sequence Number 1.

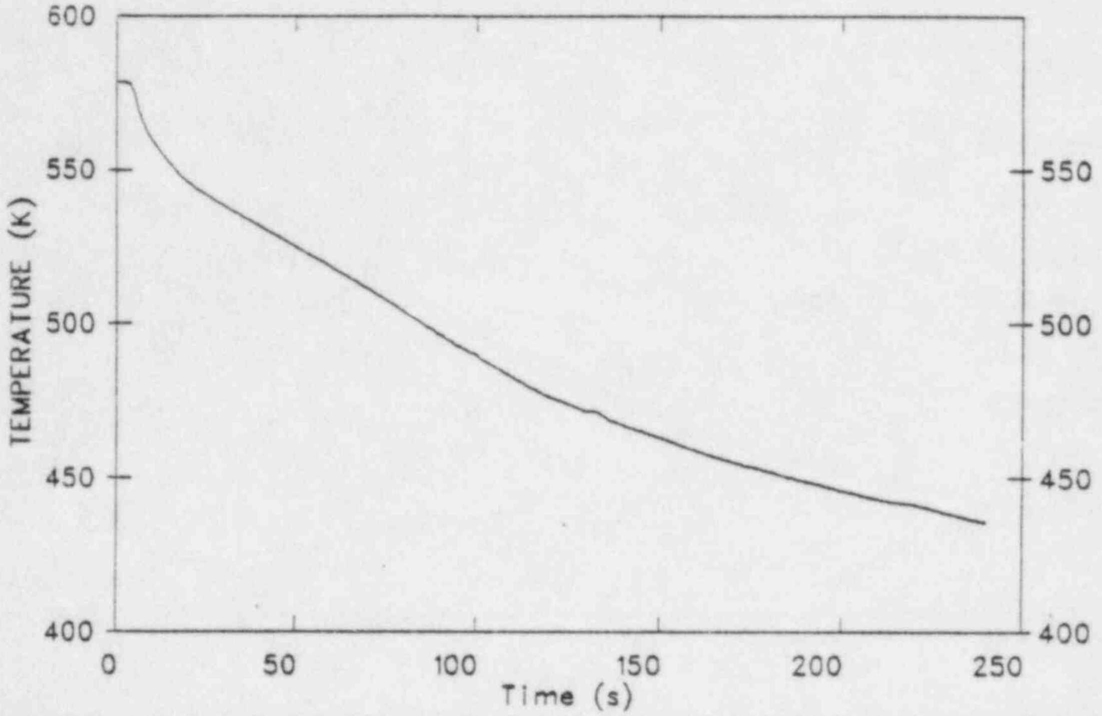

Figure 4. RCS average temperature for Reactor Coolant System Overcool Sequence Number 1.

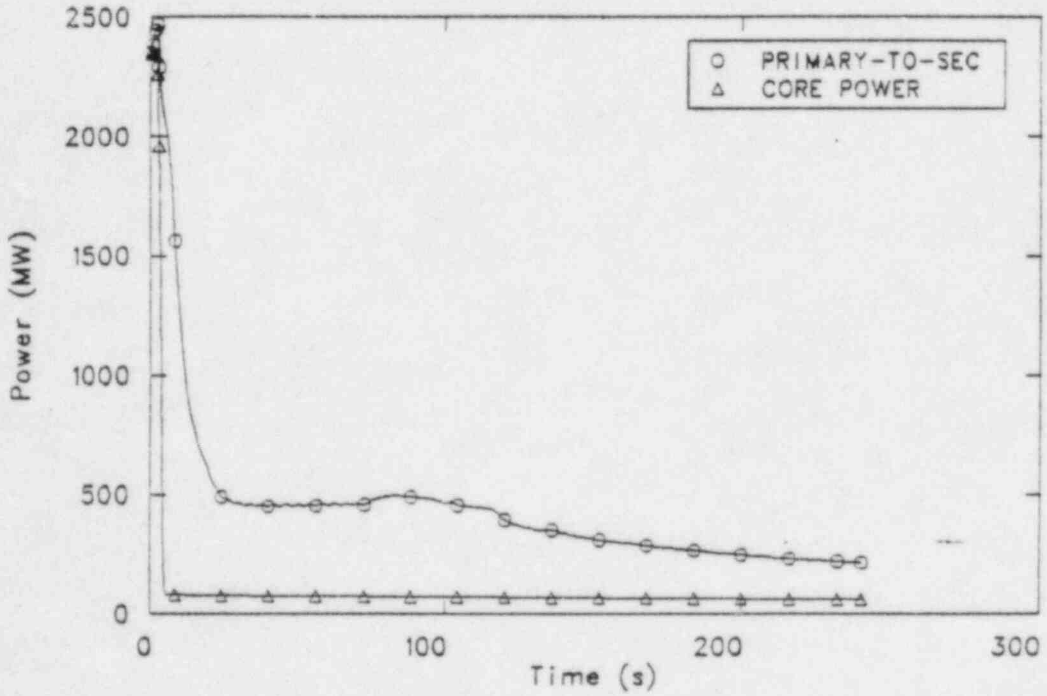

Figure 5. Primary to secondary heat transfer and core power for Reactor Coolant System Overcool Sequence Number 1.

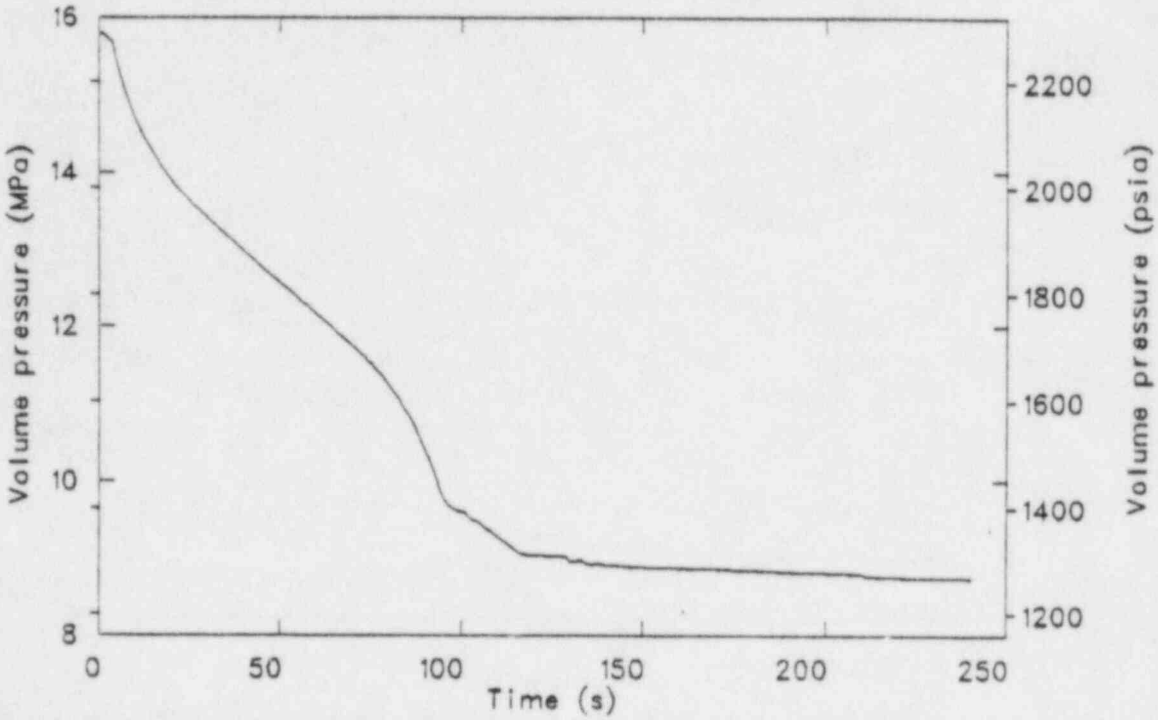

Figure 6. RCS pressure for Reactor Coolant System Overcool Sequence Number 1.

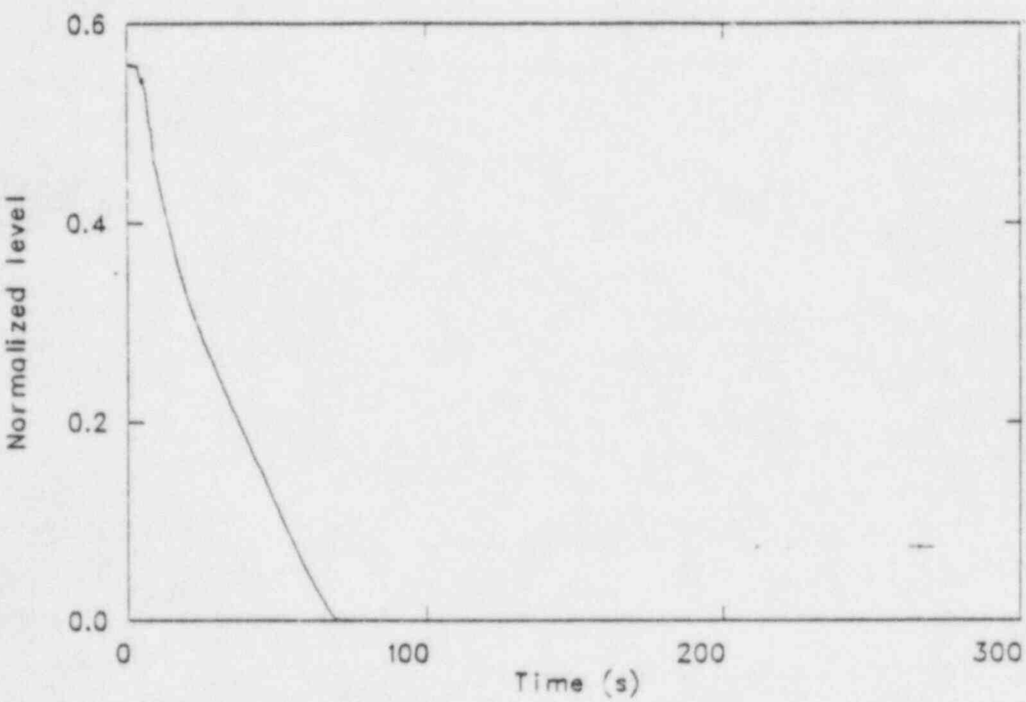

Figure 7. Pressurizer level for Reactor Coolant System Overcool Sequence Number 1.

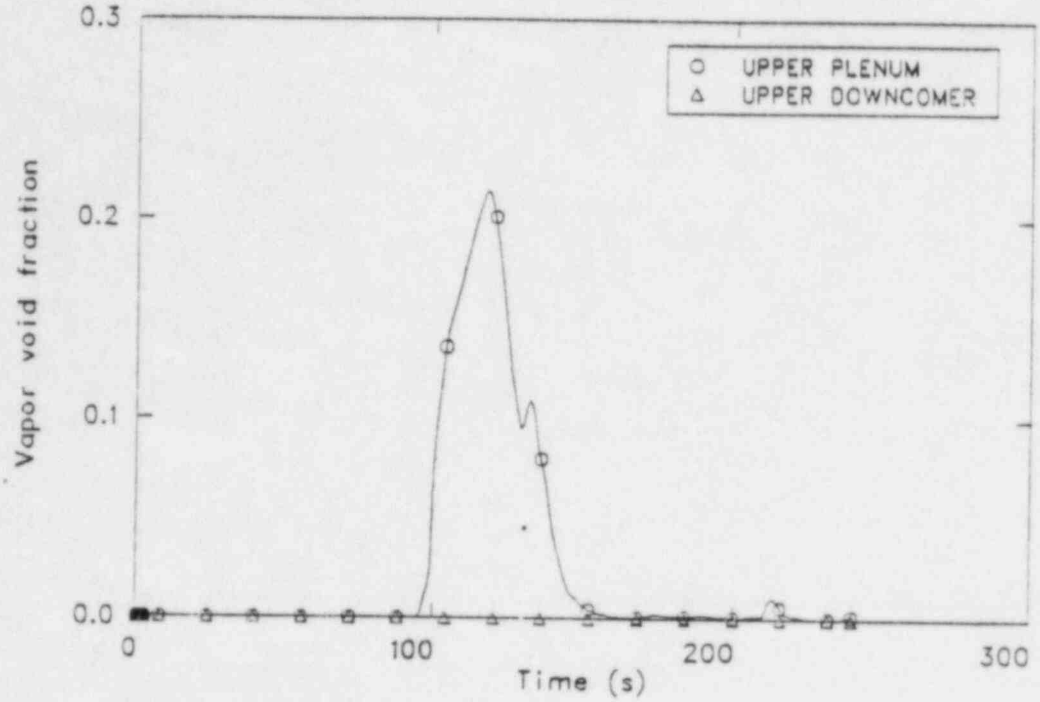

Figure 8. Reactor upper plenum void fraction for Reactor Coolant System Overcool Sequence Number 1.

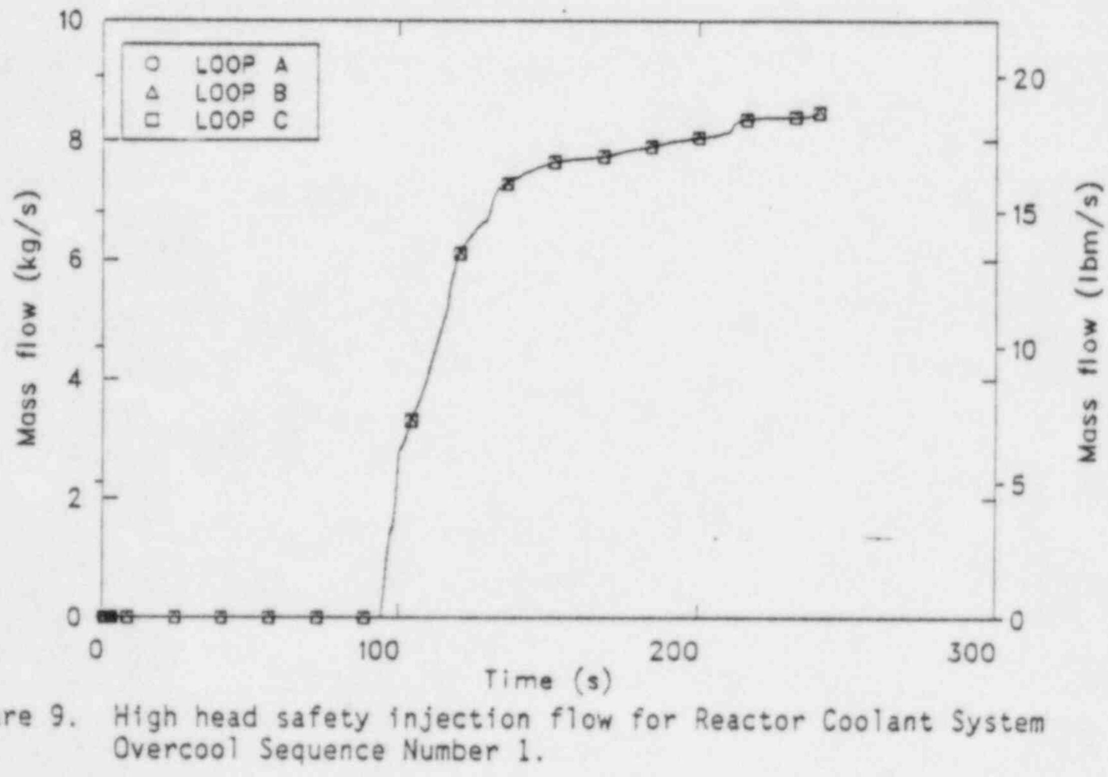

Figure 9. High head safety injection flow for Reactor Coolant System Overcool Sequence Number 1.

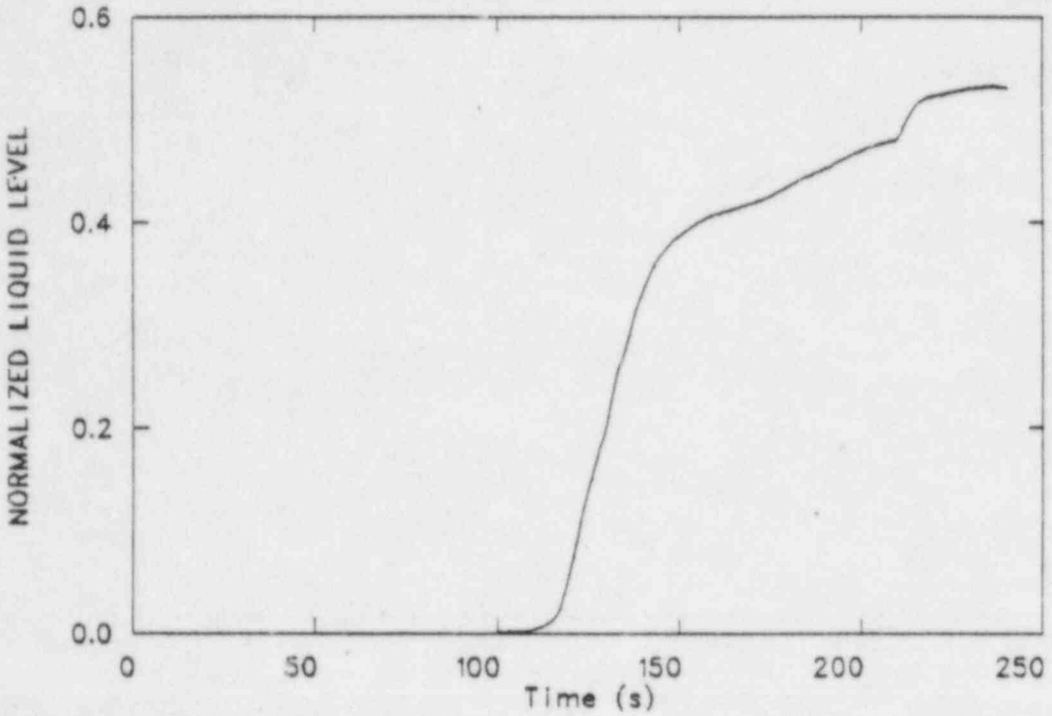

Figure 10. Upper head void fraction for Reactor Coolant System Overcool Sequence Number 1.

are in manual with all other parameters being controlled automatically. The transient was initiated by failing the steamline PORVs open at time t = 0.0 s. No aggravating failures were assumed for this sequence.

The reactor is subcritical at the start of this sequence which means that the reactor coolant pumps (RCPs) are the only source of heat to the RCS. The steamline PORVs will discharge more energy to the atmosphere than is added by the RCPs which will result in a cooldown of the RCS.

The steamline PORV flow rates are shown in Figure 11. The valves were fully opened by 1 s. The steam generator C (SGC) PORV flow rate peaked at 114 kg/s (251 lbm/.s) in 1 s, while the steam generator A (SGA) and steam generator B (SGB) flow rates peaked 2 s later at 132 kg/s (290 lbm/s). The initial peak in the PORV flow rates was due to the high steamline pressures (7.03 MPa, 1020 psia) at the time the PORVs opened. The opening of the PORVs decreased the steamline pressure, and the PORV flow rates subsequently decreased to 100 kg/s (220 lbm/s) by 15 s.

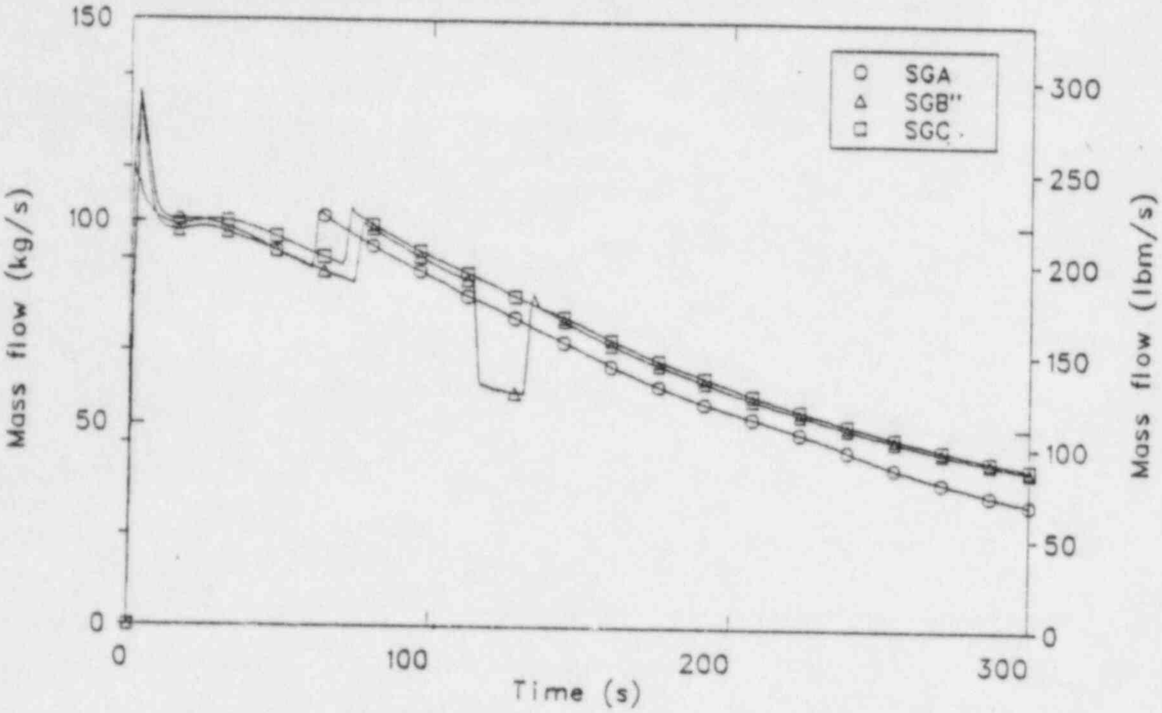

Figure 11. Steam line PORV flow rates for Reactor Coolant System Overcool Sequence Number 2.

The pressure responses in the steam domes of the three steam generators and the steam header are shown in Figure 12. The opening of the steamline PORVs resulted in the depressurization of the steamlines upstream of the steamline check valves. The valves consequently closed and remained closed during the calculation. The pressure in the steam header did not change because the turbine stop valves were closed and the steam dump valves were regulating the header pressure at 7.03 MPa (1020 psia).

The primary-to-secondary heat transfer rate response is shown in Figure 13. The heat transfer rate increased from 8 MW to about 260 MW in the first 13 s, then responded to changes in the secondary pressures and feedwater flow rates until 113 s. During the first 113 s the lower volume of each steam generator boiler region was in the subcooled nucleate boiling regime, which is characterized by high heat transfer coefficients and relatively low vapor generation rates. As the steam generators continued to depressurize, the subcooling margin in the lower boiler volumes decreased until the steam generator pressure decreased to the pressure

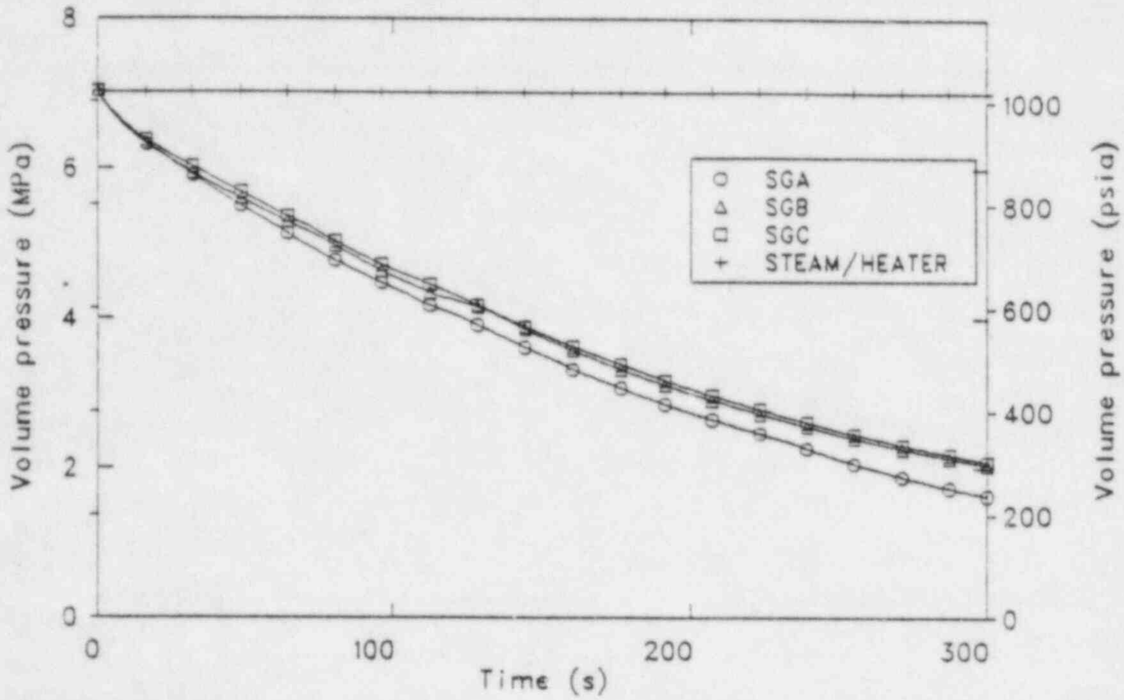

Figure 12. Secondary pressures for Reactor Coolant System Overcool Sequence Number 2.

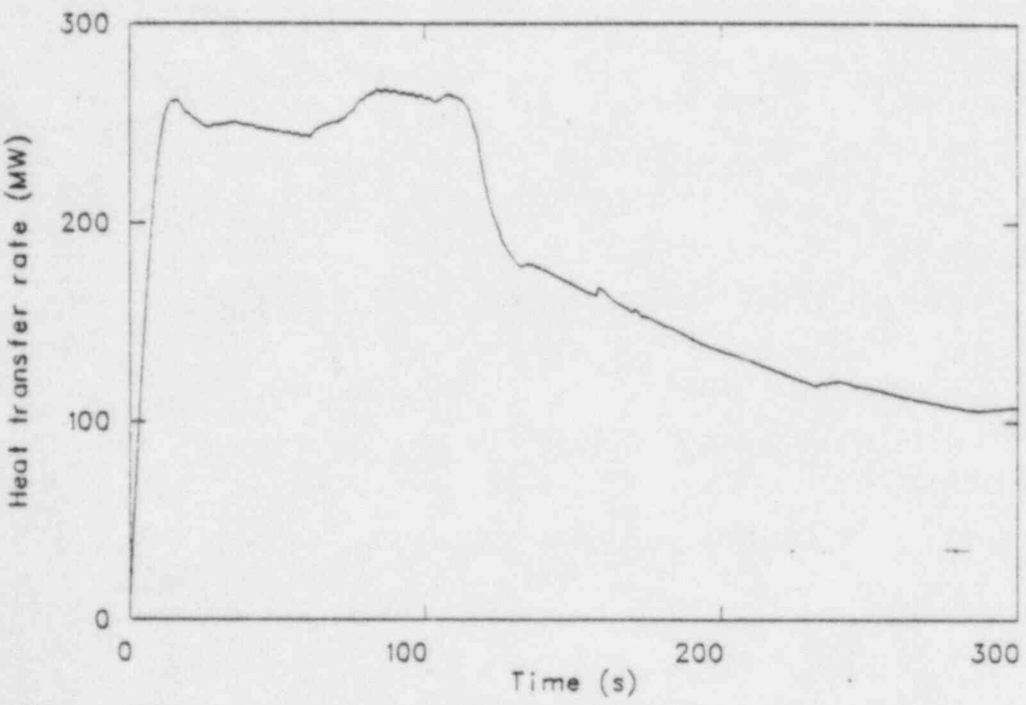

Figure 13. Primary to secondary heat transfer Reactor Coolant System Overcool Sequence Number 2.

corresponding to the fluid saturation pressure. The heat transfer mode then changed to the saturated boiling regime, and the primary-to-secondary heat transfer rates decreased.

The reactor vessel downcomer temperature response is shown in Figure 14. The downcomer temperature decreased at a constant rate for the duration of the calculation. The temperature response was dominated by the temperature difference between the primary and secondary, which was governed by the open PORVs. The downcomer temperature decreased by 55.6 K (100°F) in 230 s. The sequence of events for this calculation is provided in Table 4.

The results of this sequence analysis clearly show that when the reactor is subcritical, a failure that results in the removal of energy in excess of that being added by the RCPs, will cause a RCS cooldown. If the energy removal is substantial, such as was caused by the failure open of the steamline PORVs, then Selection Criterion 1 can be exceeded.

2.5.3 Reactor Coolant System Overpressure Sequence Number 1

At the start of the sequence, the reactor was shutdown with the RCS liquid solid at 100°F and 365 psia. The RCS was being cooled by the residual heat removal (RHR) system. The RCS pressure was being controlled by regulating letdown flow. One charging pump was in operation and provided a constant 77 gpm flow throughout the transient. The transient was initiated by a power supply failure that simultaneously closed the letdown valve and disabled one pressurizer PORV. An additional failure in this scenario was that the second pressurizer PORV did not open when the pressure exceeded the low temperature mode setpoint of 415 psia.

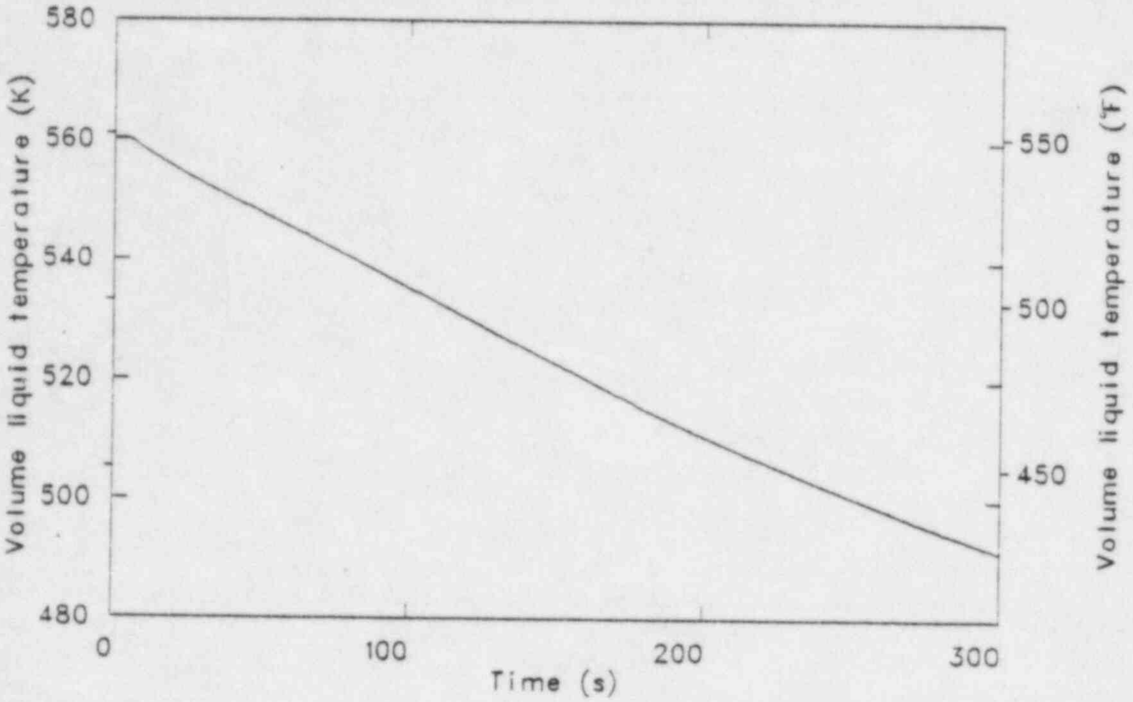

Figure 14. Reactor vessel downcomer temperature for Reactor Coolant System Overcool Sequence Number 2.

TABLE 4. SEQUENCE OF EVENTS FOR REACTOR COOLANT SYSTEM OVERCOOL SEQUENCE NUMBER 2

Time (s)	Event
0.0	Steamline PORVs begin to open.
1.0	Steamline PORVs are fully open.
3.0	Combined PORV flows peak at 832 lbm/s.
13.0	Primary to secondary heat transfer rate increased from 8 MW to 260 MW.
14.9	Safety injection actuation signal (SIAS) on one out of three high steam header to steamline pressure differential (100 psid). Main feedwater (MFW) pumps tripped. Motor driven auxiliary feedwater (MAFW) pumps initiated.
15.0	Steamline PORV combined flow at 655 lbm/s.
113.0	Primary to secondary heat transfer rate began decreasing due to change from subcooled to saturated nucleate boiling.
230.0	Reactor vessel downcomer temperature had decreased 100°F from the initial value.
250.0	End of calculation.

The RELAP5 model described previously (Section 2.4) was modified to optimally represent this scenario by deleting the secondary coolant system. The secondary coolant system was not important for this scenario because it was not needed as a heat sink due to the operation of the RHR system. The RHR system was not modeled explicitly because its volume was small compared to that of the RCS and it would not significantly affect the RCS pressure response. Since the RHR system, which removed core decay heat, was not modeled, core decay heat was also not modeled.

Table 5 presents a sequence of events for the calculation. This sequence was initiated by the isolation of letdown flow at 0.0 s. The RCS pressure, shown in Figure 15, then began to rise due to the addition of 77 gpm of charging to a closed, liquid-solid system. The RCS pressure increased rapidly and at 10.5 s the low temperature mode setpoint of the pressurizer PORV was reached. However, the PORV was assumed to fail to open and the pressure continued to rise. The calculation was terminated at 105 s when the pressure reached 1015 psia. The rate of pressure increase was nearly constant at 6 psi/s throughout the transient.

The deterministic analysis for this sequence shows that during cold shutdown with the RCS liquid solid, the RCS is susceptible to pressure transients if more coolant is added to the system than is being removed. This sequence exceeded Selection Criterion 2 by exceeding the low temperature-pressure limit as defined by the 10 CFR 50 Appendix G[10] curve in the H. B. Robinson Unit 2 Technical Specifications[5].

2.5.4 Reactor Coolant System Overpressure Sequence Number 2

This sequence was initiated with the reactor subcritical, in the process of being heated up from cold shutdown in accordance with the plant procedure (General Procedure-2)[11]. The RCS temperature is 350°F with a pressure of 265 psia. There is a vapor volume in the pressurizer and the reactor coolant pumps are operating. The sequence was initiated by a malfunction in the safety injection (SI) electronics that generated a spurious SI initiation signal. The RELAP5 model described in the previous

TABLE 5. SEQUENCE OF EVENTS FOR REACTOR COOLANT SYSTEM OVERPRESSURE SEQUENCE NUMBER 1

Time (s)	Event
0.0	Letdown was isolated and one PORV disabled.
10.5	Second PORV failed to open.
105	Calculation terminated.

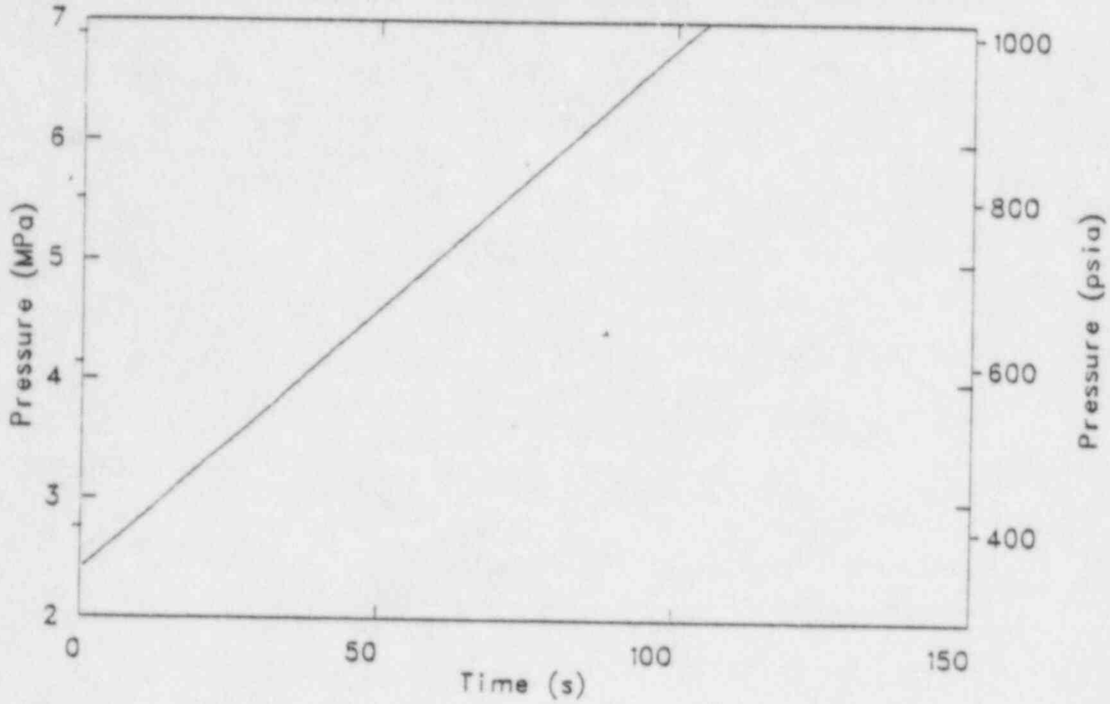

Figure 15. Pressurizer pressure for Reactor Coolant System Overpressure Sequence Number 1.

section (Section 2.5.3) was used for the calculation. A code update was used to better represent condensation during periods of inflow into the pressurizer.

Table 6 presents a sequence of events for the calculation. The transient was initiated at 0.0 by a spurious SI signal. The SI signal caused the high head safety injection (SI) and low pressure safety injection (LPSI) pumps to start and the high head SI discharge and accumulator isolation valves to open. The high head SI discharge valves were assumed to fully open in 10 s and the accumulator isolation valves in 6 s.

The RCS pressure, shown in Figure 16, increased rapidly at the start of the transient because of the compression of the vapor volume in the pressurizer that was primarily due to the large accumulator flow into the RCS (Figure 17). The check valves in the accumulator injection lines closed at 13 s when the increasing RCS pressure exceeded the decreasing

TABLE 6. SEQUENCE OF EVENTS FOR REACTOR COOLANT SYSTEM OVERPRESSURE SEQUENCE NUMBER 2

Time (s)	Event
0	SI signal.
6	Accumulator isolation valves fully opened.
10	High head SI discharge valves fully opened.
13	Accumulator check valves closed.
16	Pressurizer indicated full.
162	Pressure limit exceeded for existing RCS temperature.
192	Calculation terminated.

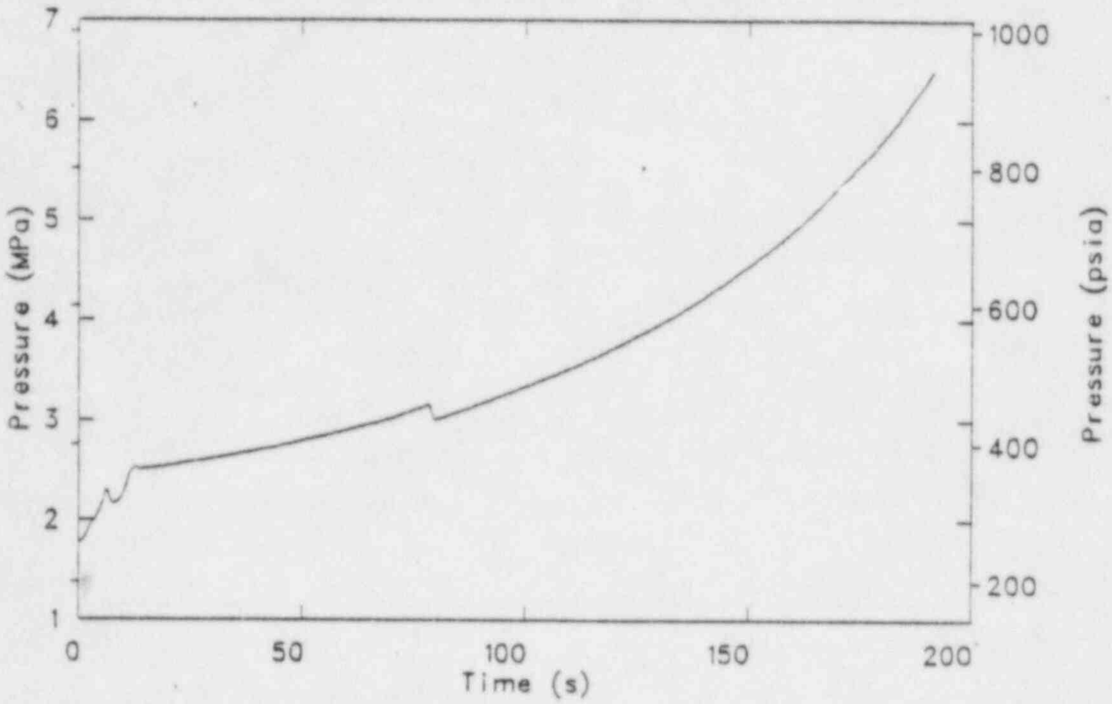

Figure 16. Pressurizer pressure for Reactor Coolant System Overpressure Sequence Number 2.

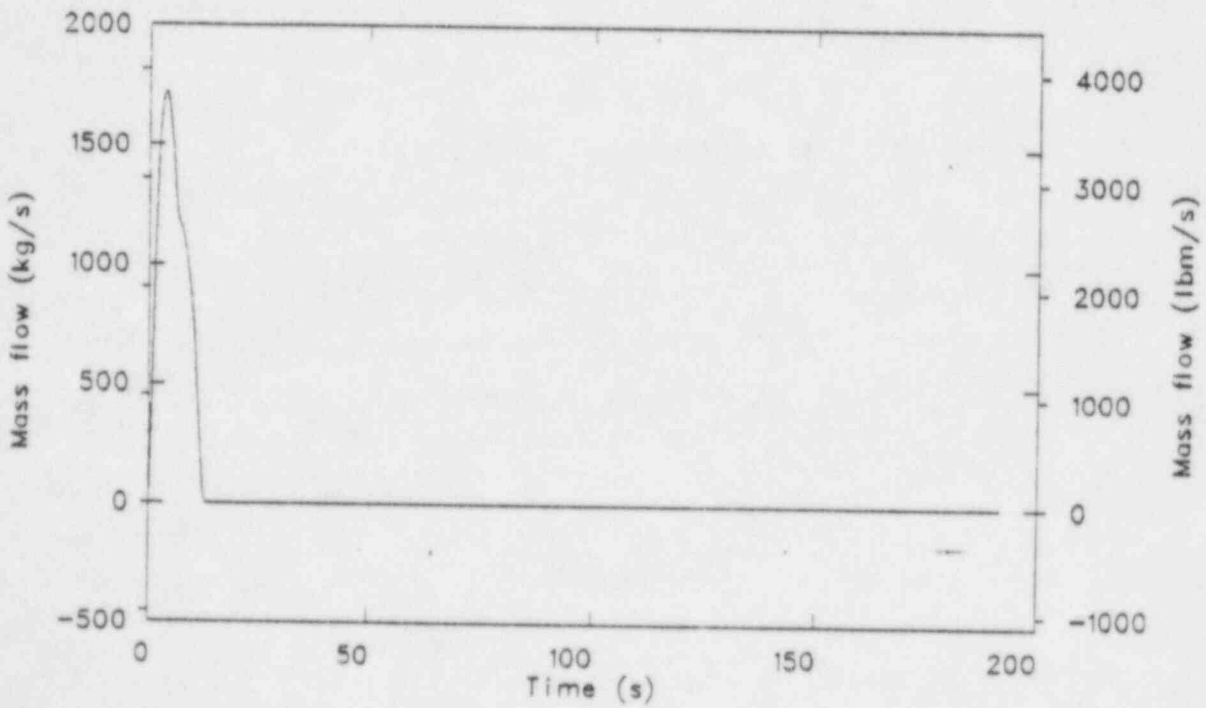

Figure 17. Accumulator flow for Reactor Coolant System Overpressure Sequence Number 2.

accumulator pressure. The pressurization rate slowed at 13 s because the accumulator flow stopped. The RCS pressure increased slowly, primarily due to the high head SI flow which is shown in Figure 18. The charging flow was not significant for this transient because it was generally less than 3% of the high head SI flow. The LPSI system was also not a factor during this transient because the RCS pressure always exceeded the shut off head of the LPSI pumps. In general, the rate of pressurization increased continuously after 15 s. This increase in rate was caused by the volume of the pressure steam volume decreasing faster than the SI flow decreased. Minor fluctuations in pressure were calculated at 10 s and 80 s. These pressure fluctuations were not realistic and were caused by condensation spikes that occurred as the mixture level crossed cell boundaries in the pressurizer.

The calculated pressurizer level is shown in Figure 19. The indicated pressurizer level started at 39% and then increased to 100% by 16 s. Over 90% of the increase in pressurizer level was due to the accumulator flow, with most of the remainder due to SI flow. Although the indicated level was 100%, the pressurizer was not liquid solid and, in fact, the actual pressurizer liquid level remained below the upper pressure tap of the level instrumentation. The discrepancy between the indicated and actual levels occurred because the indicated level was not temperature compensated.

The calculated downcomer fluid temperature is shown in Figure 20. The downcomer temperature dropped about 20°F at the start of the transient, primarily due to the flow of cold (80°F) accumulator water into the RCS. After the accumulator check valves closed, the temperature oscillated somewhat and then decreased slowly, due to SI flow, for the remainder of the calculation. Because the RCPs were on, the RCS was well mixed and the results shown in Figure 20 were representative of the entire RCS.

Given a spurious safety injection signal after the pressurizer PORV mode switch has been repositioned to "normal" and the emergency core cooling system (ECCS) has been enabled, the deterministic analysis shows that the Technical Specification temperature-pressure limit[5] will be

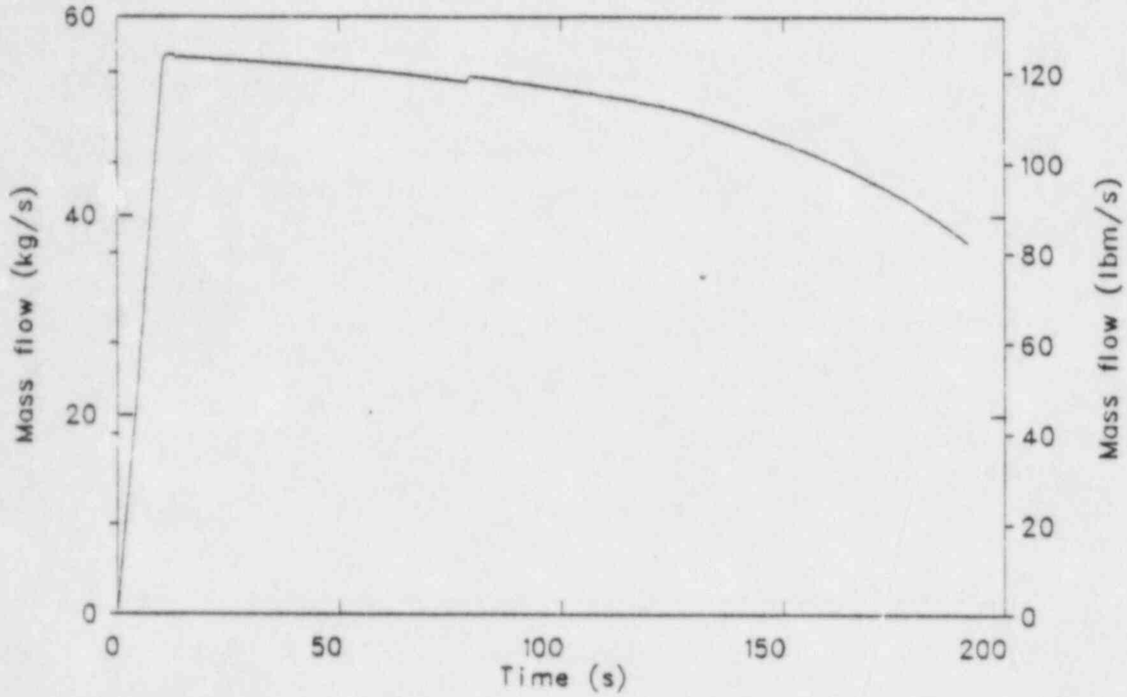

Figure 18. High head safety injection flow for Reactor Coolant System Overpressure Sequence Number 2.

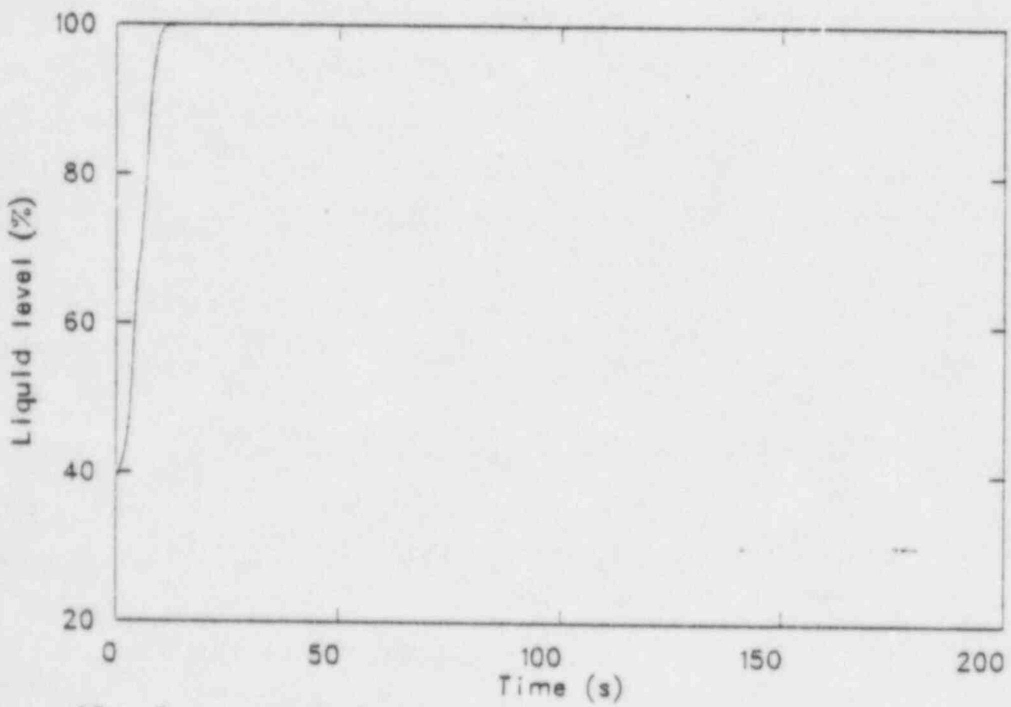

Figure 19. Pressurizer level for Reactor Coolant System Overpressure Sequence Number 2.

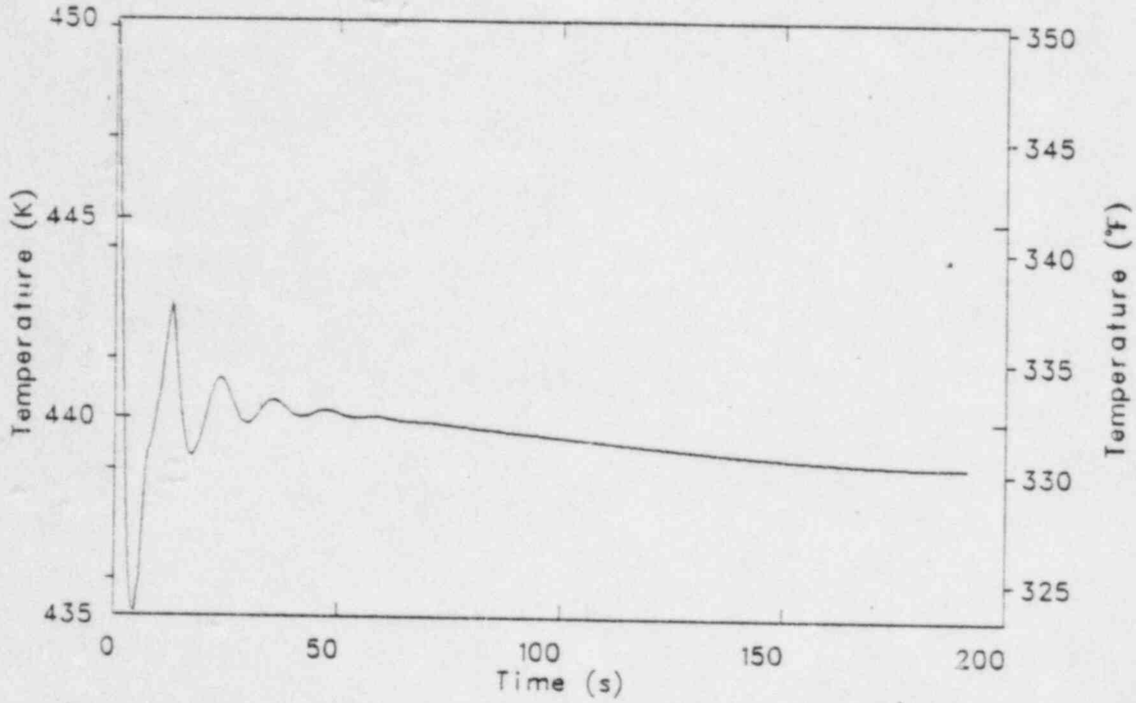

Figure 20. Reactor vessel downcomer fluid temperature for Reactor Coolant System Overpressure Sequence Number 2.

exceeded when the pressure increases above 720 psia with a temperature of 330°F is at 162 s. It should be noted that this event requires conditions that would exist only a few hours during each cooldown/heatup evolution. During the heatup, the plant is only susceptible to this event from 350°F until approximately 470°F where the PORVs and safety valves will protect the plant from overpressurization.

2.5.5 Steam Generator Overfill Sequence Number 1

The initial plant conditions for Steam Generator Overfill Sequence Number 1 are the plant is at 5% reactor power and the rod control, feedwater control, and turbine electrohydraulic control (EHC) are in manual with all other systems controlling in automatic. A low initial power was used in the calculation because it resulted in a larger possible steam flow-feed flow mismatch.

The transient was initiated by opening the steam generator A (SGA) main feedwater (MFW) control valve at a rate of 10%/s. The transient was terminated after 240 s when it was determined that the SGA narrow range (NR) level had peaked.

The feedwater flow rates to the three steam generators are shown in Figure 21. The opening of the SGA main feedwater (MFW) control valve at 10%/s resulted in an increase in feedwater flow into SGA from 17 Kg/ (38 lbm/s) to 587 Kg/s (1295 lbm/s) by 10 s. The feedwater flow rate remained essentially constant from 10 s to 35.7 s, when the MFW pump was tripped and the SGA feedwater line was isolated due to the SGA NR level reaching 75%. Motor-driven auxiliary feedwater flow was started when the MFW pump was tripped. The auxiliary feedwater preferentially flowed into SGA for the remainder of the calculation (the auxiliary feedwater flows from a common header into the steam generator with the lowest pressure).

The steam generator NR level responses are shown in Figure 22. The SGA NR level began increasing at the start of the transient due to the opening of the SGA main feedwater control valve. The SGA NR level reached 75% at 35.7 s, thereby tripping off the MFW pump, and isolating the SGA MFW line from the steam generator. The increase in SGA level between 36 s and 70 s was due to liquid inventory redistribution, and auxiliary feedwater flow. The SGA NR level reached 96.6% at 210 s and remained above 96% for the remainder of the calculation.

Steam generator liquid carryover may be inferred from the steam generator steam dome qualities, which are shown in Figure 23. The unaffected steam generator steam dome qualities remained at 1.0 during the calculation, which implies that there was no carryover in these two steam generators (SGB and SGC). The quality in the SGA steam dome started decreasing at 205 s due to liquid carryover from the separator region. The SGA steam dome quality was 47% at the end of the calculation.

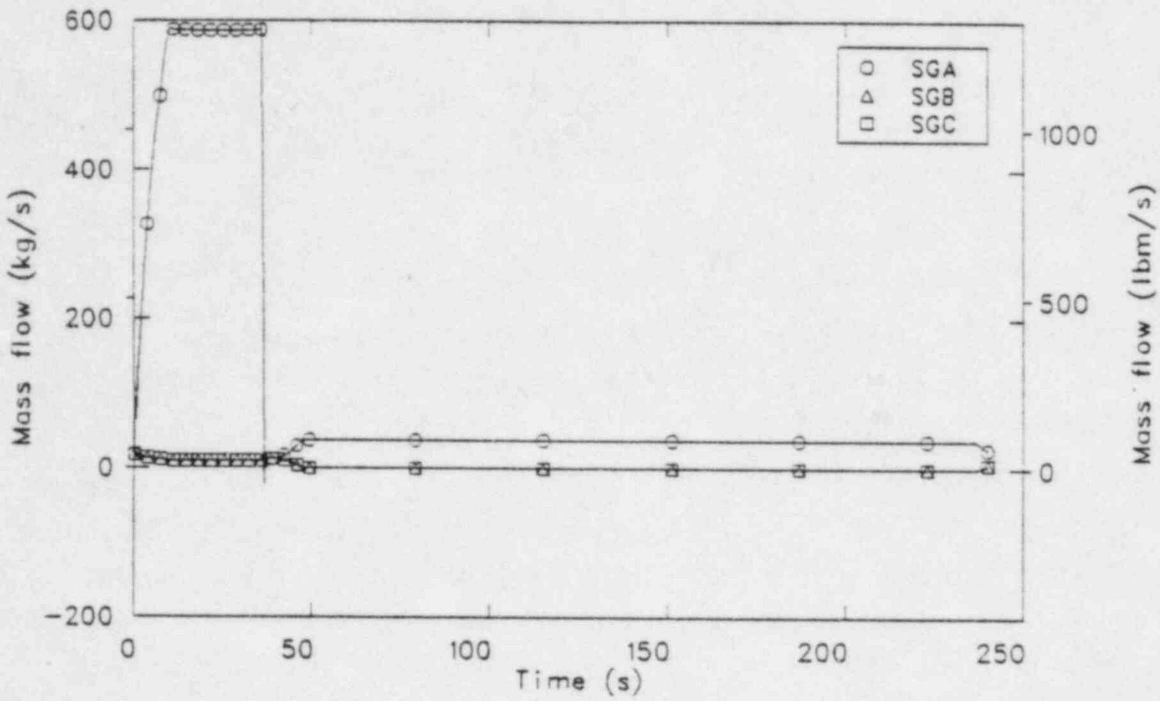

Figure 21. Feedwater flow rates for Steam Generator Overfill Sequence Number 1.

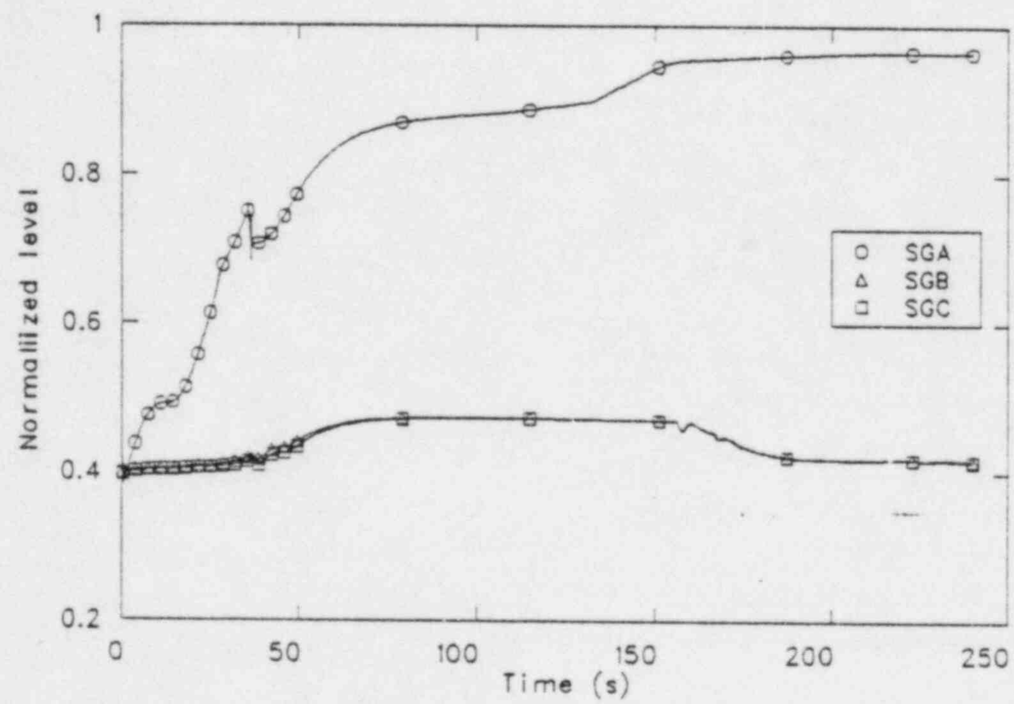

Figure 22. Steam generator NR levels for Steam Generator Overfill Sequence Number 1.

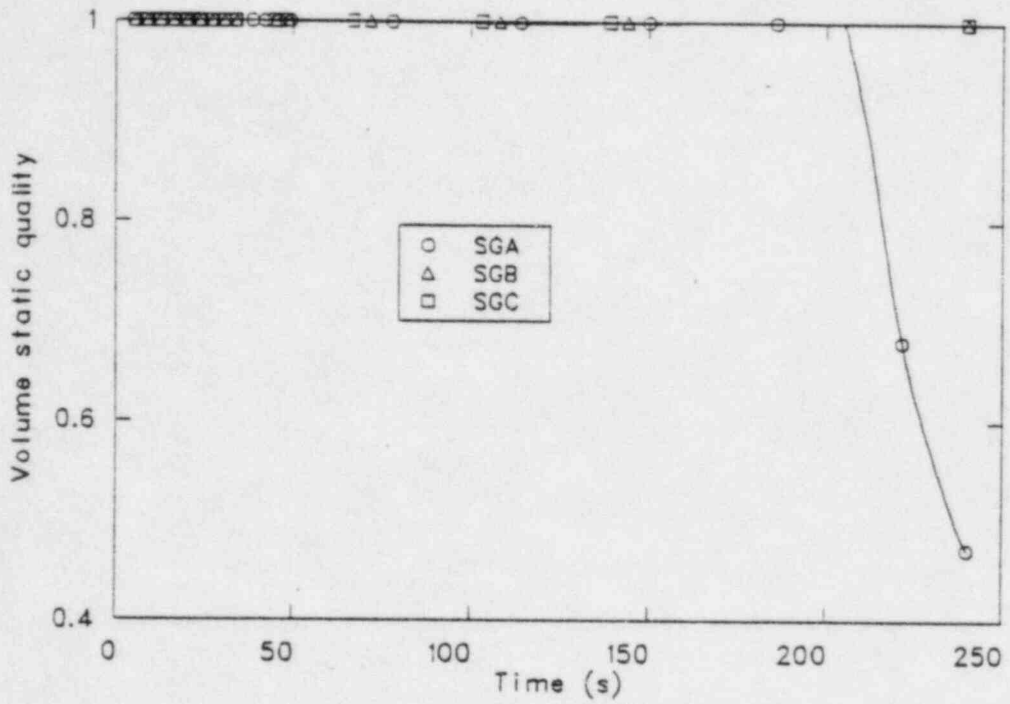

Figure 23. Steam generator steam dome quality for Steam Generator Overfill Sequence Number 1.

The pressure responses of the three steam generators and the steam header are shown in Figure 24. The opening of the SGA MFW control valve resulted in a 1.9 MPa (275 psi) depressurization of the feedwater header within the first 10 s. The corresponding 30 K (54°F) decrease in the feedwater saturation temperature resulted in an increase in the vapor generation rates, and consequently the steam generator pressures. The steam header pressure began decreasing after 22 s due to the controlling action of the steam dump system, which regulates the header pressure at 7.03 MPa (1020 psia).

The steam line mass flow rate responses of the three steam generators are shown in Figure 25. The steam flow rates were controlled by the steam dump valve through the first 36 s of the calculation. The SGA steam line check valve closed at 36.1 s when the SGA steam line pressure became less than the header pressure.

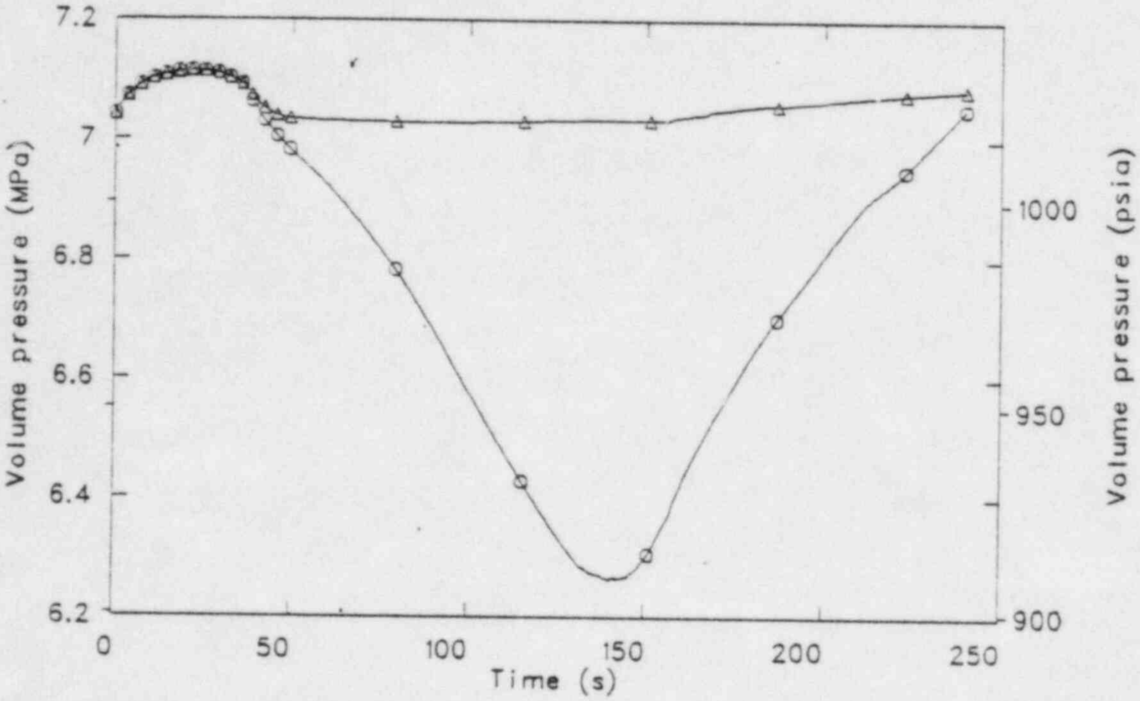

Figure 24. Steam generator steam pressure for Steam Generator Overfill Sequence Number 1.

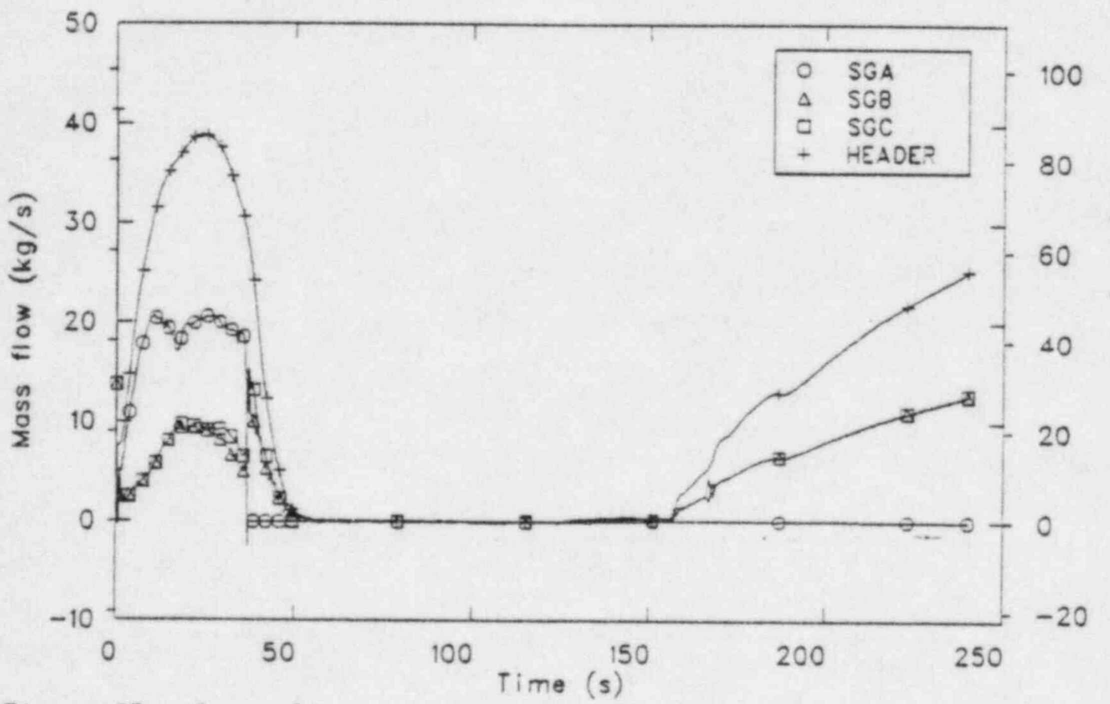

Figure 25. Steam line and steam dump flow rates for Steam Generator Overfill Sequence Number 1.

The steam dump valve mass flow rate response is also shown in Figure 25. The mass flow rate began increasing at the start of the transient due to the increased vapor generation in the three steam generators. The increase in mass flow rate continued through the first 22 s, then decreased as the steam dump valve began closing to regulate the steam header pressure. The steam dump valve was closed by 55 s and remained closed until the header pressure exceeded 7.03 MPa (1020 psia) at 127 s. The steam dump valve flow increased for the remainder of the transient due to the increase in steam generator pressures.

The RCS Loop average temperatures are shown in Figure 26. The average temperatures were essentially constant during the first 12 s of the transient. The Loop A average temperature then started decreasing followed by a similar response in the other two loops 5 s later. The Loop A temperature decreased to 552.3 K (535.4°F) by 47 s then increased for the rest of the transient. The Loop B and C average temperatures exhibited the same trend, but only decreased to 556.9 K (542.8°F) by 66 s. The temperature responses of the three loops were the same for the remainder of the transient. Since the reactor was at power, the net result was an increase in the RCS average temperatures.

The sequence of events for Steam Generator Overfill Sequence Number 1 is shown in Table 7. The deterministic analysis of this sequence showed that a failure that results in a high feedwater flow rate can result in a steam generator overfill even if the MFW pumps are tripped and isolated at the high SG level setpoint (75% NR). The overfill occurs as a result of the auxiliary feedwater flow which adds mass to the affected steam generator at a rate greater than the removal rate due to blowdown and steam flow. Because feed flow must exceed steam flow in order for the level to increase, the initial power must be low enough that steam flow does not exceed auxiliary feedwater flow, or the level will not increase above the 75% NR high level trip. When other scenarios were analyzed (see Appendix C.7) that utilized the same failure mode as this sequence, but

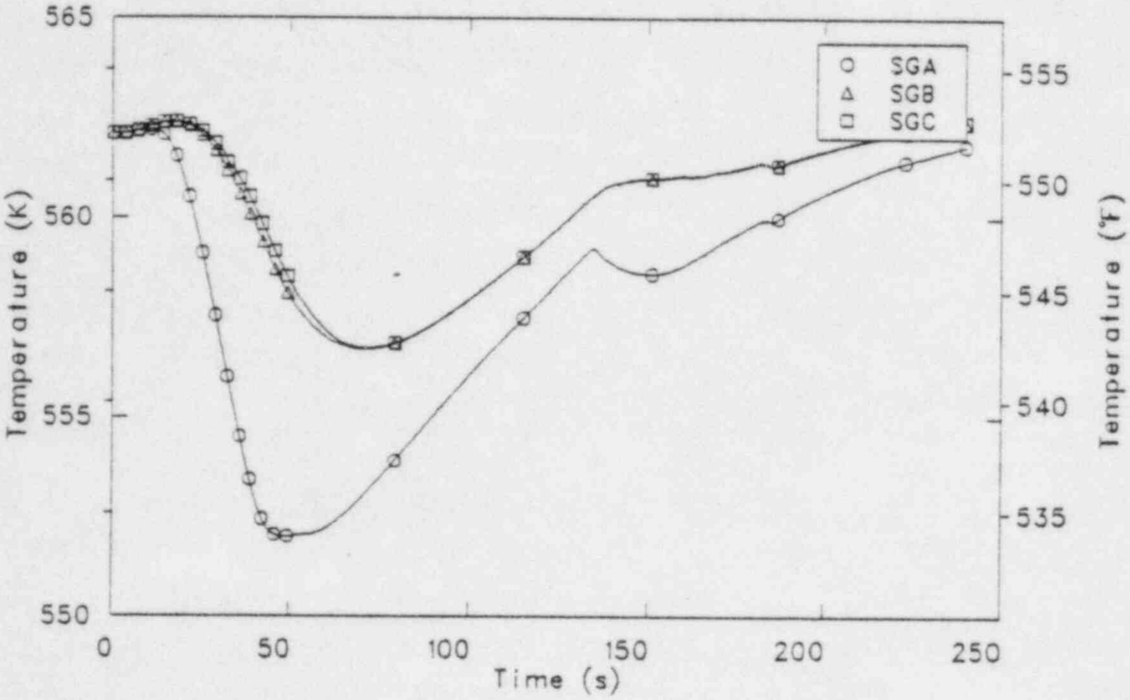

Figure 26. RCS loop average temperatures for Steam Generator Overfill Sequence Number 1.

TABLE 7. SEQUENCE OF EVENTS FOR STEAM GENERATOR OVERFILL SEQUENCE NUMBER 1

Time (s)	Event
0.0	Transient initiated by opening SGA MFW control valve.
10.0	SGA MFW valve wide open.
22.0	Steam dump valve flow peaked at 39 kg/s (86 lbm/s).
35.7	MFW pump tripped on 75% SGA NR level.
36.1	SGA steam line check valve closed.
55.0	Steam dump valve closed.
127.0	Steam dump valve opened to control steam header pressure.
150.0	SGA boiler volumes reached saturation pressure and began voiding.
196.0	SGA steam line check valve reopened.
210.0	SGA NR level reached 96.6%.
240.0	Transient terminated.

started at higher initial power levels, the calculations showed a decrease in steam quality; however, the affected steam generator level did not exceed 75% NR.

2.5.6 Steam Generator Overfill Sequence Number 2

The initial conditions assumed for the analysis of this sequence were that the plant was at 67% reactor power and rod control was in manual with all other control systems operating in automatic. The transient was initiated by failing the SGA controlling level instrument to zero. Additionally, a second level instrument on SGA did not respond to the changing steam generator level during the transient. The calculation was stopped at 400 s when the SGA liquid carryover did not significantly change for 100 s.

The MFW flow rate responses are shown in Figure 27. The SGA MFW flow rate increased from 266 Kg/s (586 lbm/s) at the start of the transient to 622 Kg/s (1371 lbm/s) by 7.3 s, when the SGA MFW control valve reached the fully open position. The SGA MFW flow rate then increased more slowly to 753 Kg/s (1660 lbm/s) by 260 s due to the effect of reduced feedwater temperature caused by the increased feedwater velocity in the feedwater heaters. The SGB and SBC MFW flow rates remained nearly constant as their respective MFW control valves responded to the decrease in feedwater flow rates caused by the opening of the SGA MFW valve.

The steam generator level responses are shown in Figure 28. The SGA NR level increased to 80% in 60 s and then increased to 96% by 260 s. The NR levels in the other steam generators remained within 2% of the setpoint level (52%) during the transient.

Moisture carryover in SGA may be inferred from the steam quality calculated for the steam generator steam dome, which is shown in Figure 29. Liquid carryover in SGA began at 20 s, which corresponds to the time of SGA separator flooding. The oscillations in quality between 20 s and 60 s were due to the oscillations in the separator recirculation flow

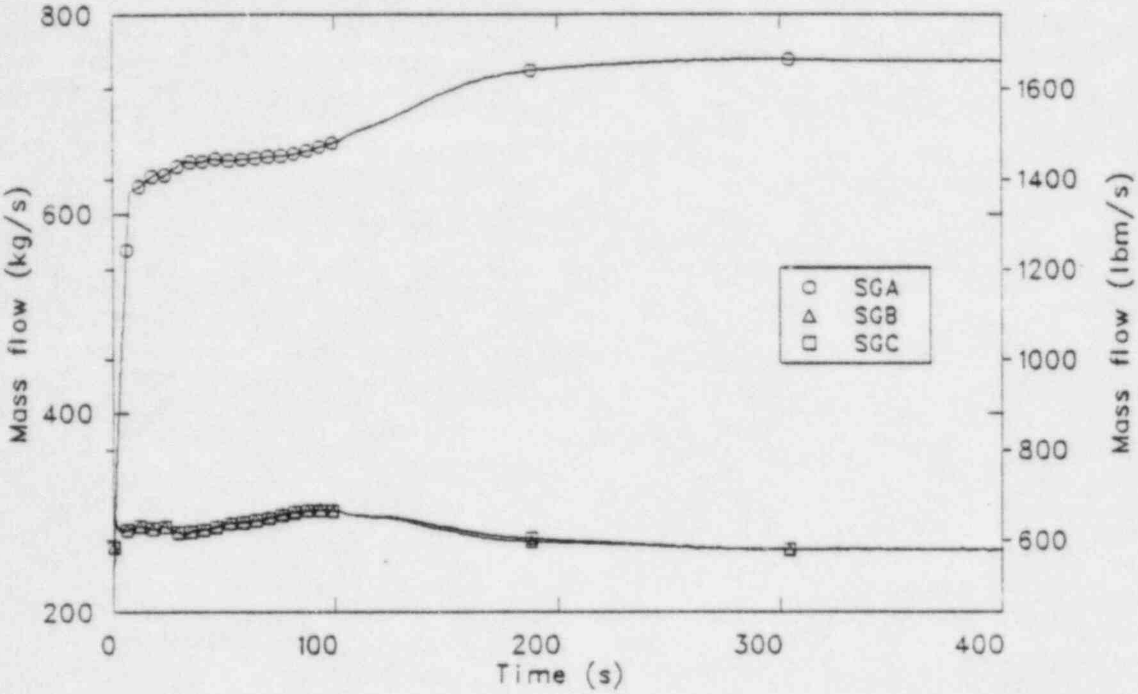

Figure 27. Feedwater flow rates for Steam Generator Overfill Sequence Number 2.

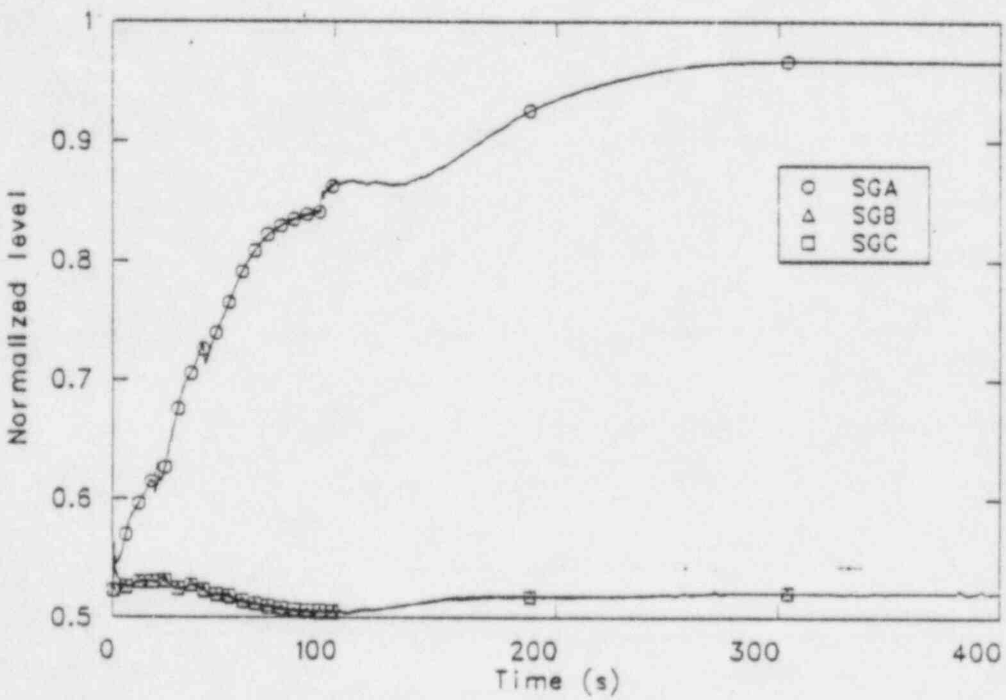

Figure 28. Steam generator NR levels for Steam Generator Overfill Sequence Number 2.

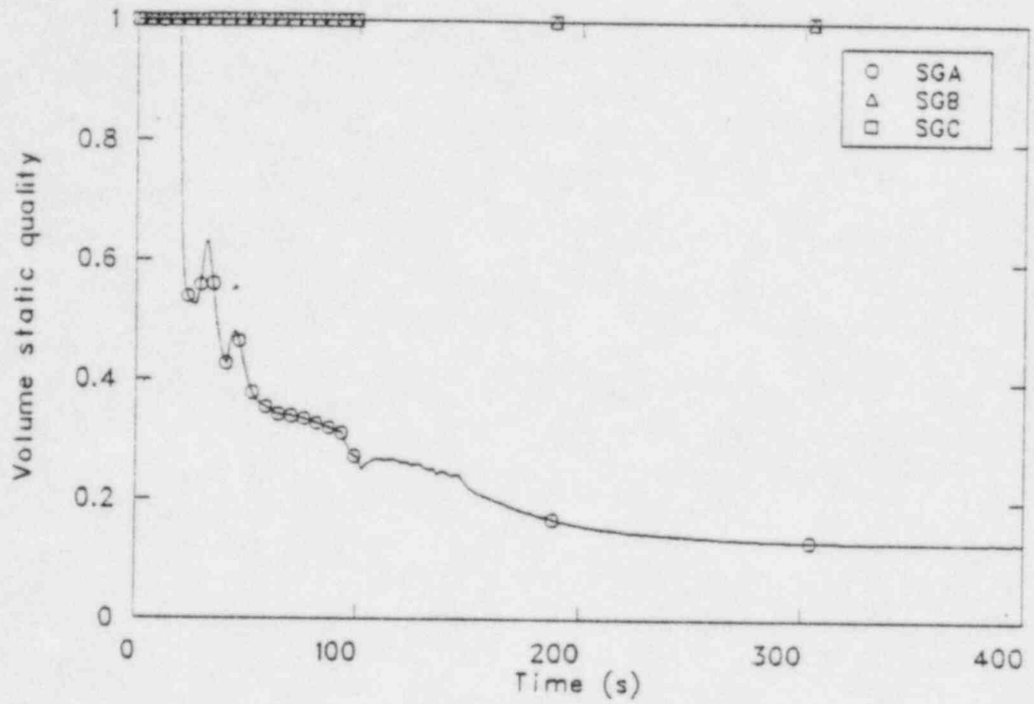

Figure 29. Steam generator steam quality for Steam Generator Overfill Sequence Number 2.

rate as the steam generator downcomer approached liquid solid conditions. The steam quality decreased at 90 s as the downcomer volume, receiving feedwater from the feed ring, became water solid. The steam quality was 13% by 300 s.

The steam generator steam flow rates are shown in Figure 30. The steam flow rates in the unaffected steam generators (SGB and SGC) initially oscillated in response to oscillations in the feedwater flow. The SGB and SGC steam flow rates decreased from 300 kg/s (661 lbm/s) at the start of the calculation to 265 kg/s (584 lbm/s) by 300 s.

The steam flow rate from SGA decreased during the first 20 s as the lower boiler volume became subcooled, thereby decreasing the vapor generation rate. The continued increase in feedwater flow into SGA flooded the separator by 20 s, resulting in the relatively sudden increase in steam mass flow rate from 20 s to 90 s. Reverse flow from the steam generator

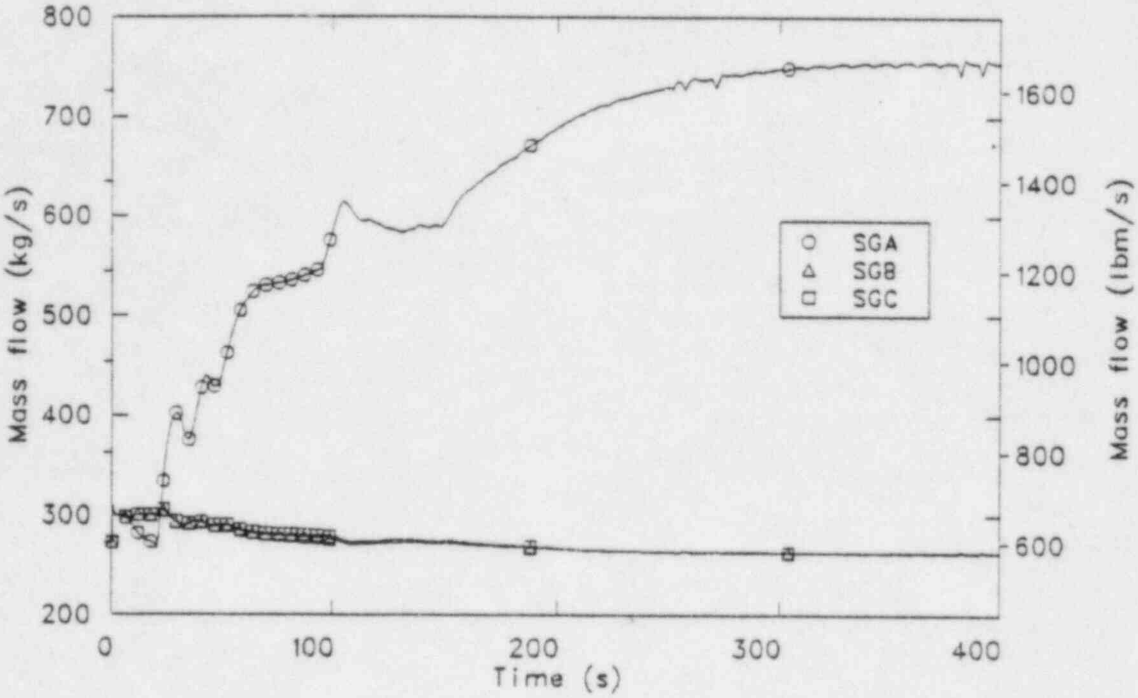

Figure 30. Steam flow rates for Steam Generator Overfill Sequence Number 2.

downcomer into the separator at 90 s resulted in the increased steam mass flow rate between 90 s and 100 s. The steam mass flow rate increased between 145 s and the end of the calculation as the SGA secondary cooled, which resulted in an increase in the steam density, and hence the steam mass flow rate.

The steam generator pressure responses are shown in Figure 31. The opening of the SGA MFW control valve in response to the failed level instrument resulted in substantially increased feedwater flow rates through the feedwater heaters, which resulted in decreasing the feedwater temperature at the inlet to the steam generators. The reduction in feedwater temperature resulted in cooling the steam generator secondary systems which reduced the steam dome pressures, and consequently, the steam header pressure.

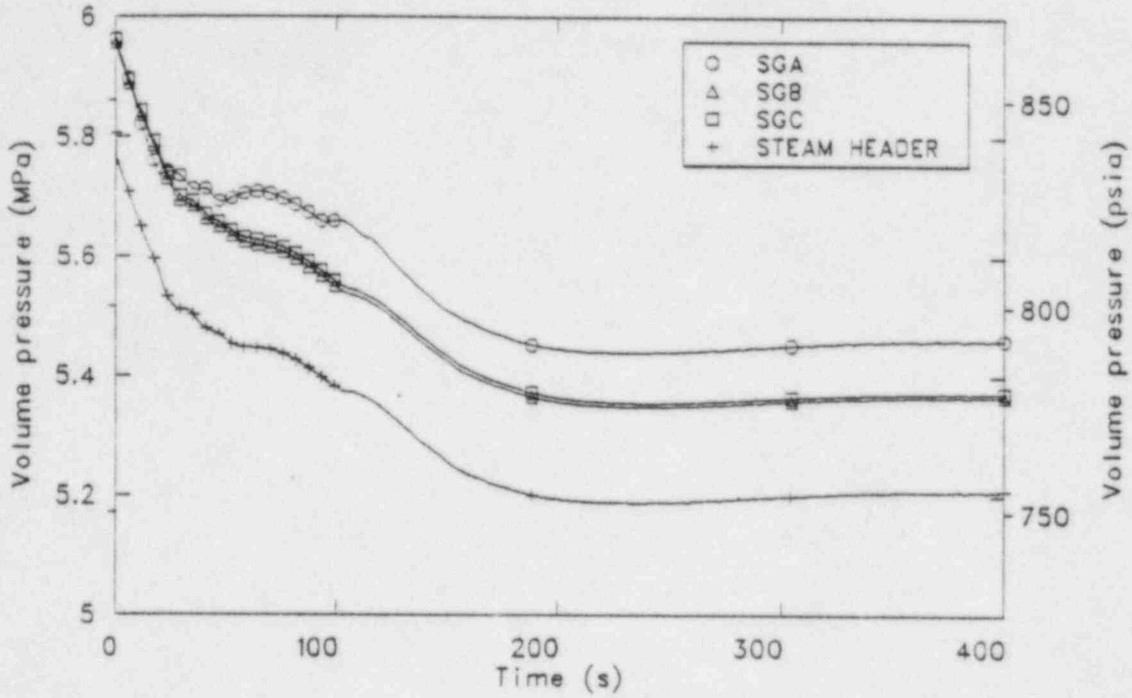

Figure 31. Steam pressures for Steam Generator Overfill Sequence Number 2.

The RCS loop average temperatures are shown in Figure 32. The three loop average temperatures decreased at the same rate during the first 120 s of the transient due to the effect of lowering the feedwater temperature. The Loop A temperature decreased faster than the temperatures of the unaffected loops between 120 s and 200 s since SGA had a larger primary-to-secondary temperature differential which resulted in a greater primary-to-secondary heat transfer rate.

The pressurizer pressure response is shown in Figure 33. The pressure initially decreased from 15.38 MPa (2230 psia) to 15.03 MPa (2176 psia) in 50 s. The pressure decreased to its minimum point of 15.00 MPa (2176 psia) by 167 s and then increased for the remainder of the transient as the primary temperatures stabilized and the pressurizer heaters were able to recover the pressure.

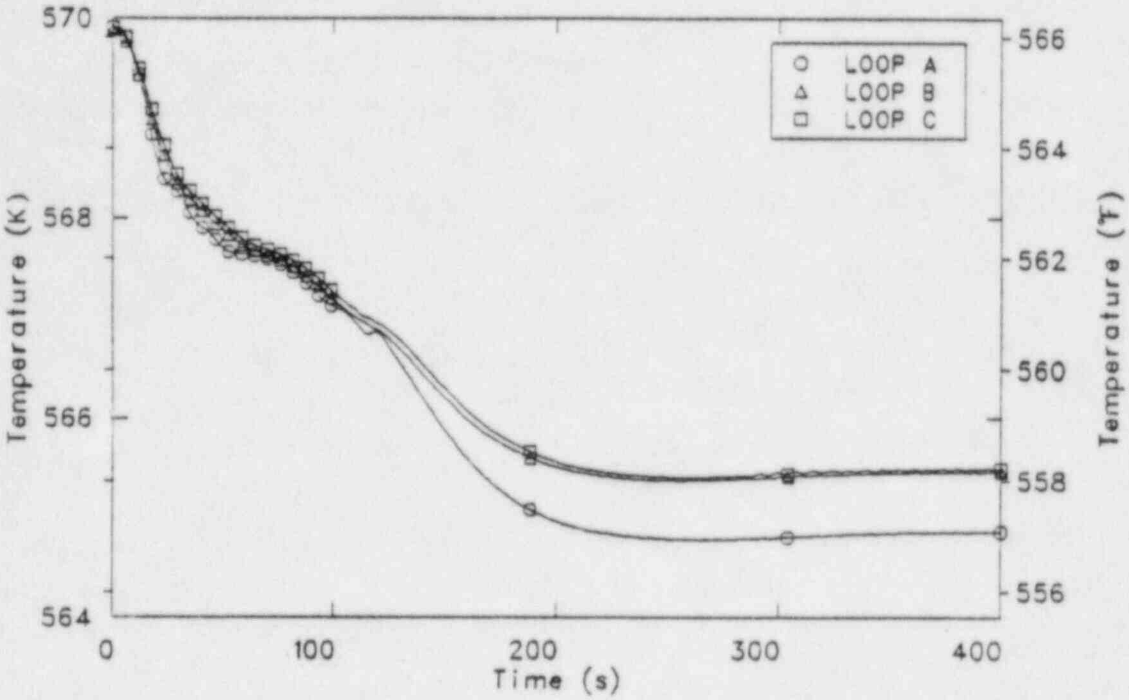

Figure 32. RCS loop average temperatures for Steam Generator Overfill Sequence Number 2.

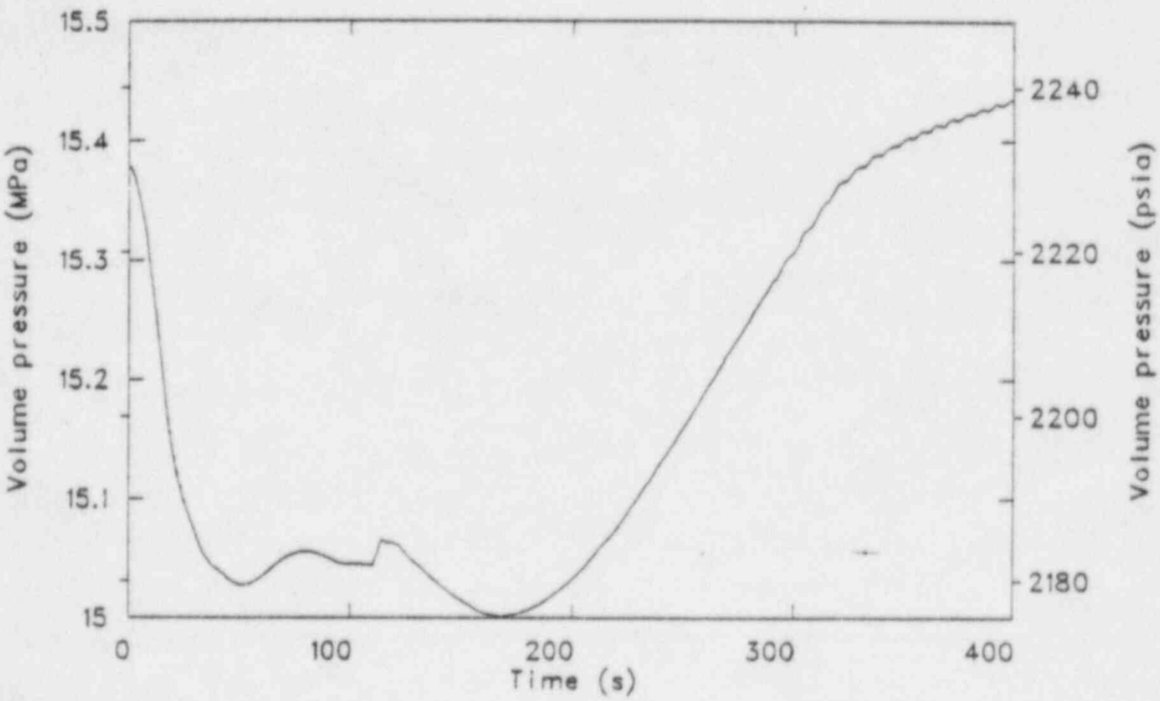

Figure 33. Pressurizer pressure for Steam Generator Overfill Sequence Number 2.

Reactor power is shown in Figure 34. The reduction in the RCS temperature resulted in an increase in reactor power due to the the moderator temperature coefficient. The 17 s delay in reactor power increase at the start of the transient was due to a 0.8 K (1.5°F) deadband on the moderator temperature coefficient calculation. The delay in the reactor power increase did not significantly affect the results of the calculation. The reactor power reached 1740 MW by 250 s and remained essentially constant for the remainder of the calculation.

A summary of the sequence of events for Steam Generator Overfill Number 2 is provided in Table 8. The deterministic analysis of this sequence showed that if a failure causes a high feedwater flow rate and a second failure prevents the automatic trip and isolation of the MFW pumps at the high level trip point, a steam generator overfill will occur as defined by Selection Criterion 7. However, the second failure cannot result in a reactor trip, for that would result in closure of the MFW control valves and limit feedflow to that supplied by the auxiliary feedwater pumps. Under these conditions, auxiliary feedwater flow would require greater than 10 minutes to overfill a steam generator due to the lower SG level at which auxiliary feedwater flow was initiated, and the greater amount of steam that would be drawn off by the steam dumps to cooldown the RCS and remove decay heat.

2.5.7 Steam Generator Tube Rupture Sequence Number 1

The initial plant conditions for Steam Generator Tube Rupture Sequence Number 1 were assumed to be that the plant was at 102% reactor power, the RCS pressure was 2280 psia, and all systems were controlling in automatic. There are no system failure modes that have been identified for initiating a steam generator tube rupture. Therefore, this sequence was initiated by opening a break in one steam generator (SGA) tube adjacent to the cold leg tube sheet. Additionally, a complete loss of offsite power was analyzed as an aggravating failure.

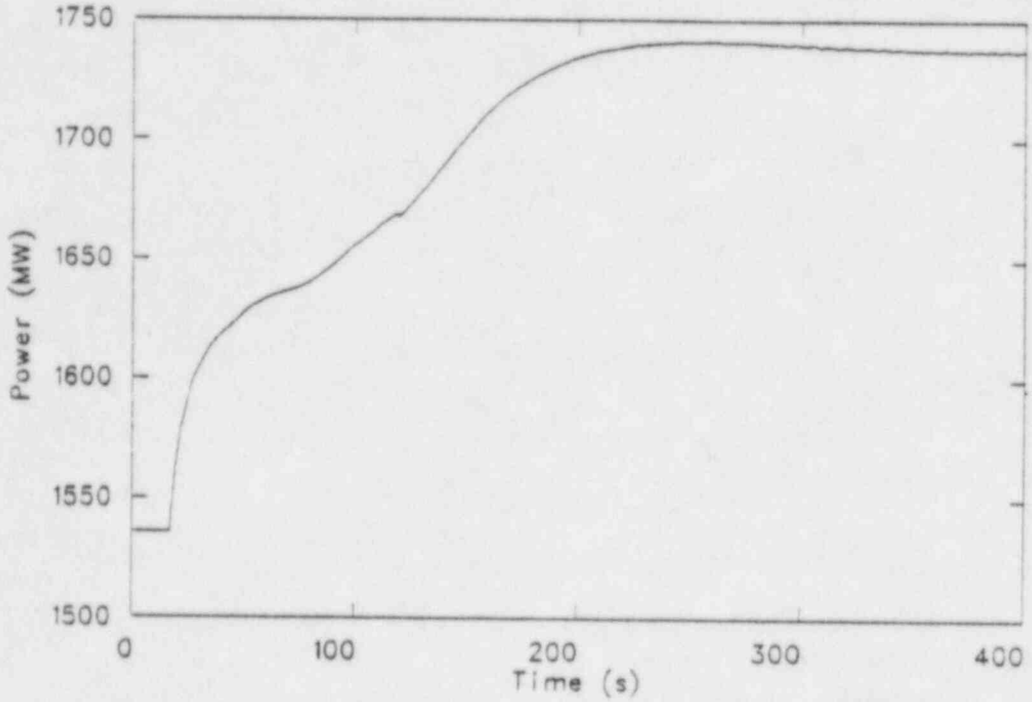

Figure 34. Reactor power for Steam Generator Overfill Sequence Number 2.

TABLE 8. SEQUENCE OF EVENTS FOR STEAM GENERATOR OVERFILL SEQUENCE NUMBER 2

Time (s)	Event
0.0	Transient initiated by failing the SGA controlling level tap to 0.0. Additionally, a second level tap on the same SG was failed at its steady state value (52.7%).
7.3	SGA MFW valve wide open.
146.0	Mass flow rates in SGA stabilized resulting in a smoothly increasing liquid carryover fraction for the remainder of the transient.
167.0	Minimum pressurizer pressure reached (2176 psia). The pressure increased for remainder of calculation.
250.0	Primary average temperatures reached new steady state values of 557°F in Loop A, and 558°F in Loops B and C. Reactor power reached new steady state value of 1740 MW.
300.0	Liquid carryover peaked at 19.2%.
400.0	Transient terminated due to steady state nature of feedwater and steam flow rates, which resulted in an essentially constant liquid carryover fraction.
	The final SGA liquid carryover fraction was >19%.

The primary and secondary system pressures in the SGA cold leg plenum and the lowest volume of the SGA boiler are shown in Figure 35. The primary system pressure initially decreased from 15.5 MPa (2250 psia) to 14 MPa (2030 psia) in 30 s. The decrease in RCS pressure was due to the combined effects of the reactor coolant pump trip and the subsequent reactor trip (which were both caused by the loss of offsite power), and the break in the steam generator tube.

The reactor core inlet and outlet temperature are shown in Figure 36. The core outlet temperature initially decreased due to the reactor trip. The outlet temperature increased from 565 K (557°F) at 20 s to 575 K (575°F) by 195 s due to the reactor coolant flow coastdown caused by the reactor coolant pump trip. The outlet temperature decreased for the remainder of the calculation due to heat removal by the steam generators and the SI and chemical and volume control system (CVCS) flows into the RCS. The reduction in the calculated RCS temperatures caused the primary system pressure to decrease due to coolant shrinkage. The rate of pressure decrease was somewhat offset by the loss of the primary-to-secondary heat sink that occurred due to the loss of reactor coolant pump flow and the closing of the turbine stop valves. The core inlet temperature decreased throughout most of the calculation due to the heat removal by the steam generators.

The RCS pressure continued to decrease due to the effect of the break and the continued RCS cool down. The loss of primary system inventory eventually resulted in the reactor vessel upper head voiding at 360 s, which then governed the rate of RCS depressurization for the remainder of the calculation.

The steam generator secondary system pressure initially increased due primarily to the closing of the turbine stop valves at the start of the transient. The rate of pressure increase between 30 s and 360 s was mainly due to the break flow into the secondary. The depressurization of the

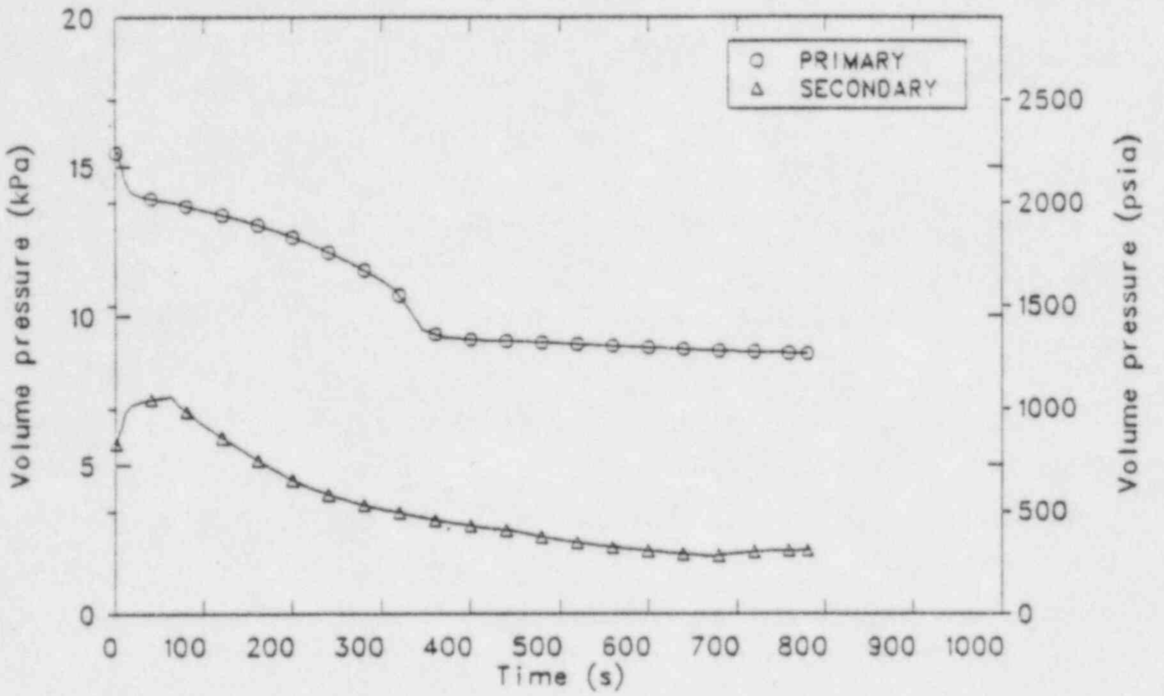

Figure 35. RCS and secondary pressures for Steam Generator Tube Rupture Sequence 1.

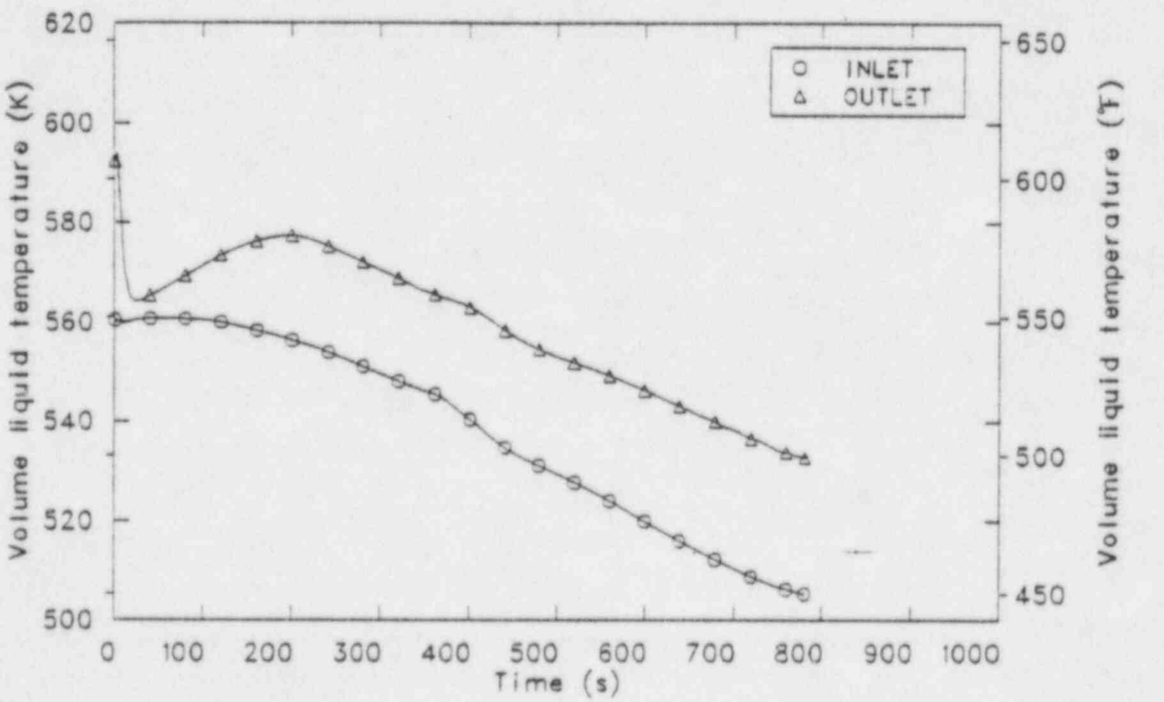

Figure 36. Core inlet and outlet temperatures for Steam Generator Tube Rupture Sequence Number 1.

secondary system after 360 s was caused by the stuck open steam line PORV. The secondary pressure at the end of the calculation was approximately 2 MPa (290 psia).

The void fraction in the reactor vessel upper head and in the volume immediately below the vessel upper head are shown in Figure 37. The decrease in RCS pressure resulted in a brief period of void formation in the vessel upper plenum. The refilling of the reactor coolant system by the CVCS charging pumps and the high head SI pumps resulted in the void collapsing by 440 s.

Void formation in the reactor vessel upper head began at 360 s and continued to increase for the remainder of the calculation. The rate of void formation was initially about 0.4%/s, but it then decreased as the system refilled. The observed rate of void fraction increase indicates that the upper head void fraction would not exceed 70%; hence, voiding in the core region is unlikely.

The break mass flow rate and the SGA PORV mass flow rate are shown in Figure 38. The break flow, on the tube side of the break, increased to 8 kg/s (17.6 lbm/s) when the break was initially opened, then remained between 5 and 8 kg/s (11-17.6 lbm/s) for the duration of the calculation. The constant flow rate was due to choked flow conditions on the tube side of the break.

The break flow rate on the tube sheet side of the break initially increased to 35 kg/s (77.2 lbm/s) and then decreased to approximately 20 kg/s (44.1 lbm/s) by 30 s as the primary system pressure decreased and the secondary system pressure increased. The break flow on the tube sheet side of the break did not choke during the calculation. The difference between the break flow rate responses was due to the conditions upstream of the two break junctions. The opening of the break resulted in significant voiding in the broken tube (nearly 70% void fraction was predicted at 350 s), while the SGA outlet plenum did not void during the calculation, as

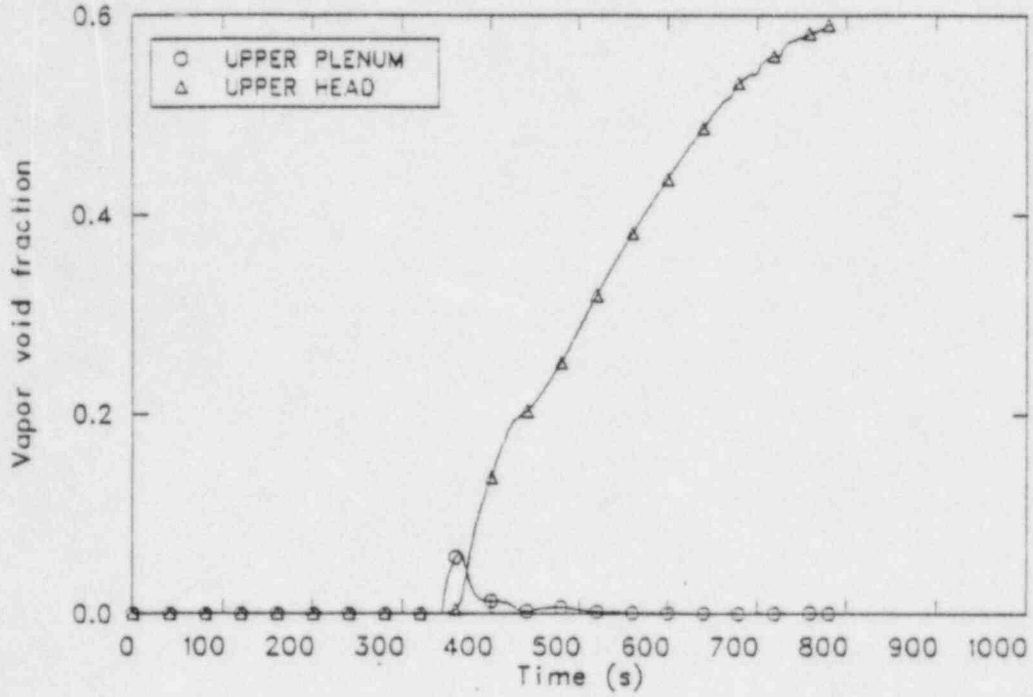

Figure 37. Reactor vessel void fractions for Steam Generator Tube Rupture Sequence Number 1.

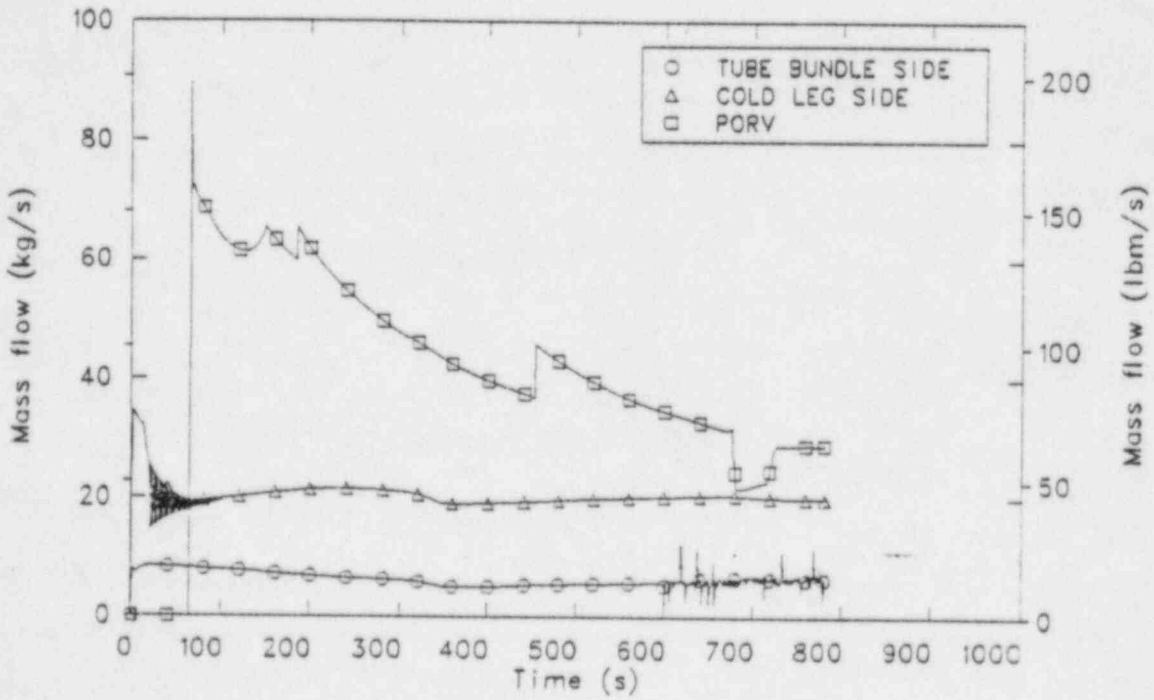

Figure 38. Break and steam line PORV flow rates for Steam Generator Tube Rupture Sequence Number 1.

shown in Figure 39. Consequently, the break flow was single phase liquid from the SGA outlet plenum, but was two phase vapor from the tube bundle side. The higher density of the plenum fluid offset the slower break flow velocity.

The SGA PORV flow rate response is shown in Figure 38. The PORV opened at 65 s and was assumed to stick, therefore, it remained open for the remainder of the calculation. The PORV flow initially increased to 90 kg/s (198.4 lbm/s) then decreased for the remainder of the calculation. The sudden increase in PORV flow rate at 452 s was due to a RELAP5 restart anomaly that changed the phasic-dominated flow characteristic at the PORV. The overall effect on the integrated PORV flow rate was minor since the net increase in flow was less than 1% of the total flow.

The steam generator narrow range level responses are shown in Figure 40. The levels in the three steam generators decreased from 52% to approximately 7% during the first 40 s due to the combined effect of tripping the turbine stop valves closed and the MFW pumps off (both of these events were caused by the loss of offsite power). The loss of the main feedwater pumps was further aggravated by the isolation of the main feedwater train at 7.5 s due to the main feedwater control valves ramping shut due to the reactor trip and low RCS average temperature.

The increase in SGA NR level during the calculation was due to the break mass inflow and auxiliary feedwater (AFW) flow. The flows into SGA were offset by the flow out of the stuck open PORV. The SGA NR level reached 75% by 630 s and continued to increase for the remainder of the calculation.

The integrated break and SGA PORV masses are shown in Figure 41. The integrated break mass was higher than the PORV mass through the first 100 s, after which the integrated PORV mass exceeded the break mass. The PORV mass flow increased sharply and then slowly decreased, as indicated in Figure 38 while the break mass flow rate was essentially constant

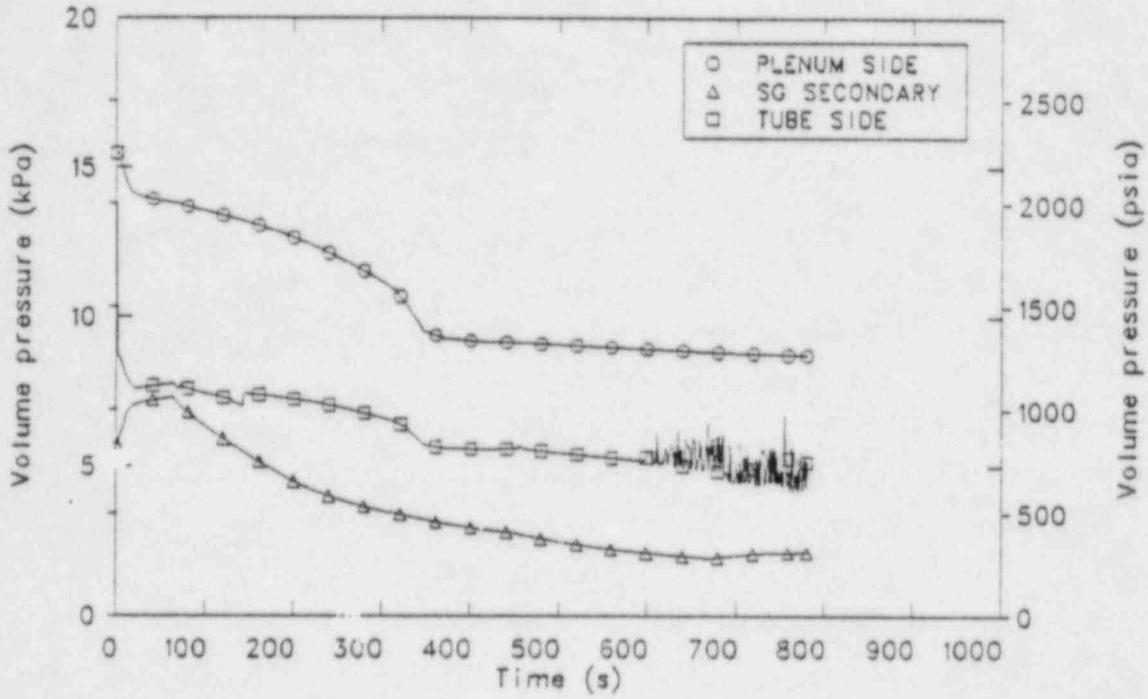

Figure 39. Break volume pressures for Steam Generator Tube Rupture Sequence Number 1.

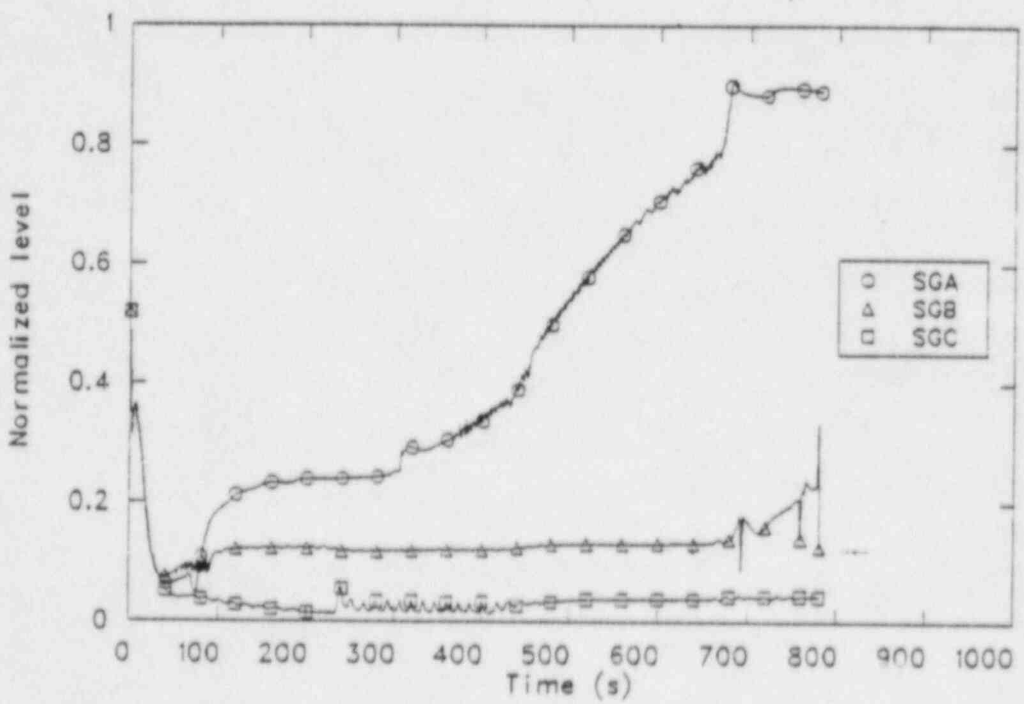

Figure 40. Steam generator NR levels for Steam Generator Tube Rupture Sequence Number 1.

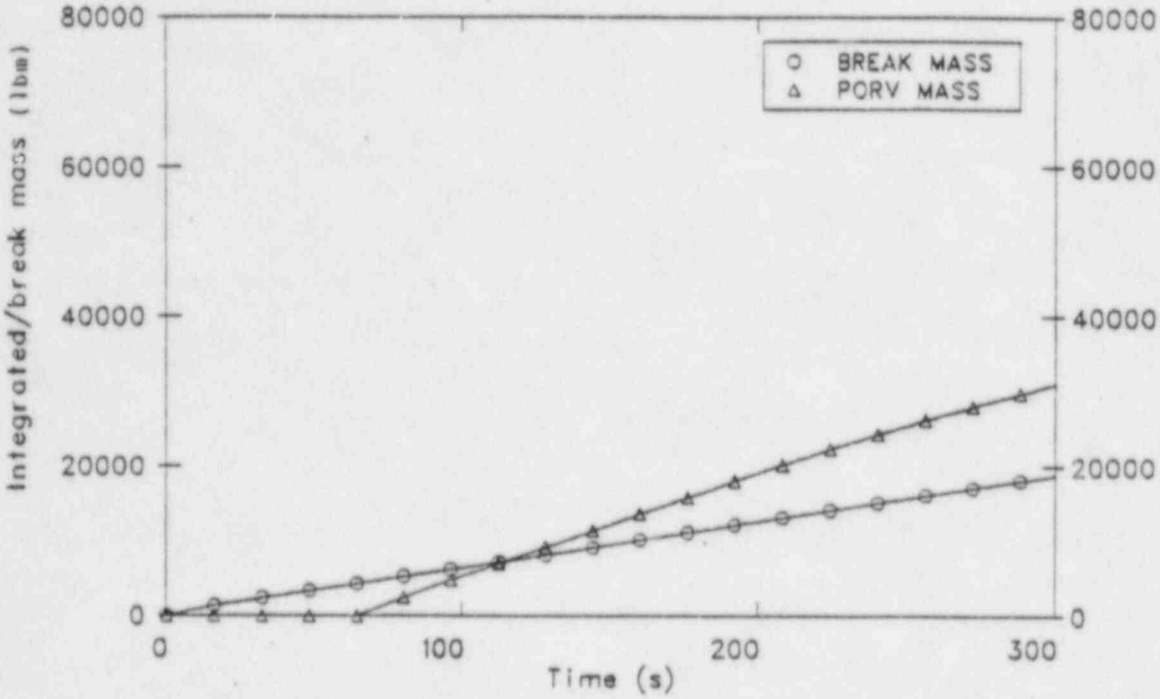

Figure 41. Break mass and PORV mass for Steam Generator Tube Rupture Sequence Number 1.

throughout the calculation. The integrated PORV mass continued to increase at a faster rate throughout the calculation, as shown in Figure 41. The PORV integrated mass flow reached 25855 kg (57000 lbm), which is the secondary coolant released to atmosphere in the FSAR analysis, by 589 s.

The calculation was terminated at 780 s when it was decided that the time (1190 s) when the break mass would exceed the break flow calculated in the H. B. Robinson FSAR analysis (70000 lbm) could be determined by linear extrapolation using the plot provided in Figure 41. The PORV mass was estimated to be 43286 kg (95429 lbm) by 1190 s.

The sequence of events for the Steam Generator Tube Rupture Sequence Number 1 is provided in Table 9. The deterministic analysis shows that the H. B. Robinson FSAR break mass and mass released to the atmosphere will be exceeded by this sequence. Given that the same RCS activity level exists

TABLE 9. SEQUENCE OF EVENTS FOR STEAM GENERATOR TUBE RUPTURE SEQUENCE NUMBER 1

Time (s)	Event
0.0	Transient initiated by opening a break in one steam generator tube in SGA adjacent to the cold leg tube sheet. Additionally, a complete loss of offsite power was assumed.
	Turbine tripped.
	Reactor tripped.
	RCPs tripped.
	MFW pumps tripped.
	Condensate pumps tripped.
	Pressurizer heaters tripped.
1.0	Control rod banks begin insertion.
	Turbine stop valves closed.
3.6	All control rod banks fully inserted.
7.5	MFW valves closed.
8.0	Steam dump valves closed for remainder of transient.
10.0	Motor driven AFW system valves fully opened.
21.2	Turbine driven AFW initiated on 2/3 low-low steam generator NR levels (15%).
65.0	SGA PORV pressure setpoint (1050 psia) reached. PORV sticks in the fully opened position.
81.0	SGA secondary system pressure lowest of three SGs. All AFW preferentially flowed into SGA.
86.9	SIAS initiated due to steam header pressure 100 psi higher than SGA steam line pressure.
250.0	Pressurizer empty.
360.0	Reactor vessel upper head began voiding.

TABLE 9. (continued)

Time (s)	Event
388.3	MSIVs closed on 2/3 low primary coolant loop temperatures (<543°F).
589.0	57000 lbm released to atmosphere through stuck open SGA PORV.
660.0	AFW sources to SGA manually isolated.
780.0	Calculation terminated.
	Primary to secondary mass = 46040 lbm
	Secondary to atmosphere mass = 69394 lbm
	Average break flow rate = 58.6 lbm/s
	Average PORV flow rate (60 s) = 63.5 lbm/s
	Estimated time for break flow into SGA to reach 70000 lbm = 1190 s
	Estimated mass discharged to atmosphere by 1190 s = 95429 lbm

as was postulated in the FSAR, with both a net increase in flow from the RCS to the secondary and from the secondary to atmosphere, there should be an increase in the offsite radiation levels from those calculated in the FSAR. Therefore, this sequence exceeds Selection Criterion 8.

The analysis of this sequence also showed that it exceeded Selection Criteria 1 and 7 (RCS overcool and steam generator overfill, respectively). However, it should be noted that an overcool and overfill would be of secondary concern in this event where the primary concern is stopping the break flow to limit the release of radioactive coolant to the atmosphere. The main steam isolation valve (MSIV) for the affected SG will be closed early in the transient, which would prevent damage of downstream components due to water hammer when overfill occurs.

2.5.8 Steam Generator Tube Rupture Sequence Number 2

The initial plant conditions assumed for this sequence were a power level of 102%, a RCS pressure of 2280 p.ia, and all control systems operating in automatic. A tube rupture is assumed to occur to initiate the event since our evaluation did not identify any system failures that can cause a tube rupture. The aggravating system failures assumed for this sequence are a failure that results in an increase in feedwater flow to the steam generator with the rupture and a failure that sticks the affected steam line PORV open when it initially opens to relieve the increasing steam generator pressure.

The underlying purpose for considering this sequence with the high feedwater flow rate was to determine if aggravating failure could increase the level in the steam generator sufficiently to have two-phase fluid flow out of the steam line PORV when the valve initially opens. Some of the PORVs and safety valves have not been tested and qualified for two-phase flow and could, therefore, be postulated to be damaged by the flow. It is postulated that if the two-phase flow damaged the steam line PORV or safety valves so they could not close, then the second aggravating failure would result as a side effect of the high feedwater flow rate failure, which would substantially increase the probability of this event occurring.

The calculation for this sequence failed after 63 s due to water property problems in the code. After a careful evaluation of the data provided by the calculation to that point, it was decided that the parameters of interest for this sequence could be extrapolated from the calculated data.

The calculation showed that at 60 s the break flow rate was 89.5 lbm/s and the feedwater flow rate into the affected steam generator was 1116.8 lbm/s, which results in a total flow of 1206.3 lbm/s into the steam generator. The only mass being removed from the SG is due to steam flow which was calculated at 996.8 lbm/s. Therefore, the net effect on the SG is an increase in mass of 209.5 lbm/s which corresponds to a rate of increase of 0.4%/s in the SG water level. At 60 s the SG NR level was 74.6%. If the calculated rate of level increase were maintained, water would enter the steamline 123.5 s after initiation of the sequence. The analysis for Steam Generator Tube Rupture Sequence Number 1 showed that the PORV opened at 65 seconds since the loss of offsite power at t=0.0 resulted in an immediate reactor trip and turbine trip. For Sequence Number 2 the turbine trip occurs at 61 s from high SG level and the reactor trip would be actuated from the turbine trip. The exact time of the PORV actuation cannot be determined, but it is postulated to occur after water enters the steamline at 123 s. Therefore, there is a possibility that the initial challenge to the steamline PORV will be made by two-phase flow.

The remainder of this sequence is expected to be similar to Steam Generator Tube Rupture Sequence Number 1, therefore, Selection Criteria 1, 7, and 8 are assumed to be exceeded.

2.5.9 Concluding Remarks

In the next section of this report, these sequences that resulted in exceeding the Selection Criteria are subjected to a probabilistic analysis to determine each sequence probability.

2.6 Mechanistic Failure Analysis

The FMEA and computer analysis identified the failure modes (system failures) that could cause one or more of the events of concern and exceed the applicable Selection Criteria. Once the failure modes were identified, a search for the failure mechanisms began.

The method used to identify potential failure mechanisms was to review applicable H. B. Robinson documents such as piping and instrumentation drawings, FSAR, and technical specifications. For this review it was assumed that no operator actions were taken in the first ten minutes following the postulated failure. This is in keeping with the guidance of proposed ANSI Standard N660.[12]

This section provides a discussion of the failure modes that were identified in Section 2.5, that could result in exceeding the criteria for reactor overcool, reactor overpressure, steam generator overfill, and steam generator tube rupture, and a discussion of the failure mechanisms that could cause these failure modes to occur.

2.6.1 Reactor Coolant System Overcool Sequence Number 1

The failure mode that initiates this scenario is inadvertent steam dump flow while the reactor is at power. All of the steam dump valves were postulated to fail open in the scenario analyzed on the computer, therefore, the following mechanistic failures have been identified that could possibly result in the occurrence of this transient:

1. The T_{ave} temperature instrument (TM-408) fails high.

2. Temperature controller TC-408E fails in the steam dump controller, or other single failures occur such as wire faults or solid state element faults.

2.6.2 Reactor Coolant System Overcool Sequence Number 2

This transient starts from hot shutdown at the no load T_{ave} of 547°F with RCPs operating. All control systems are in automatic except rod control, pressurizer pressure control, and turbine control. The initiating event in the computer analysis was an inadvertent opening of three steam line PORVs. With the reactor subcritical, a failure mechanism that would cause a substantial steam flow would result in a reactor overcool event. While a detailed sensitivity study was not performed to determine the exact amount of steam flow that would be necessary to cool the reactor 100°F during the first 10 minutes of the transient, a conservative value was provided by the Reactor Coolant System Overcool Sequence Number 2 analysis. In that analysis a reactor trip was initiated from 102% power with a subsequent failure of a steam dump valve in the open position which resulted in a 93°F decrease in reactor temperature during the first 10 minutes of the transient. This scenario was initiated at 102% power, and would therefore, include the effects of decay heat production in the core after the reactor trip which would reduce the cooldown rate. Therefore, it is assumed that in the case where the reactor is initially subcritical with no decay heat, the steam flow associated with failure of one steam dump valve to the open position (approximately 274 lb m/s) will be sufficient to result in a reactor overcool event. The following mechanistic failures are those that a detailed review has shown would result in steam flows equal to or greater than that allowed by a fully open steam dump valve:

1. A single failure occurs in the steam dump controller that sends an open signal to one or more dump valves.

2. A failure occurs in a steam dump valve that results in the valve opening.

3. A single failure occurs in the steam dump controller that sends an open signal to one or more steam line PORVs.

4. A steam line PORV control circuit or switch fails resulting in an open signal to the PORV.

5. A failure occurs in a steam line PORV that results in the valve opening.

6. A single failure occurs in the turbine EHC that results in a signal to open the turbine control valves.

7. A mechanical failure of a turbine governor and/or intercept valve causes it to fail open.

2.6.3 Reactor Coolant System Overpressure Sequence Number 1

This transient is initiated when the RCS is water solid and in a low temperature and low pressure condition (cold shutdown). The failure mode for this scenario is a loss of letdown flow coupled with a failure of both pressurizer PORVs. The PORVs can fail either together or independently and their failure can occur at any time prior to or exactly when they are challenged by the increasing RCS pressure. Discussed below are the failure mechanisms that could cause this failure mode to occur:

1. Loss of a power supply that feeds both a letdown valve and one of the PORVs, so that the letdown valve goes to its fail safe (closed) position and the PORV is rendered inoperable, and a single active failure of the second PORV (The single active failure could be any of the following: (a) failure of the pressurizer pressure instrument; (b) failure of the PORV control circuitry; (c) failure of the valve; (d) failure in the mode switch so that the low temperature-low pressure mode is not selected; (e) failure of the power supply to the valve.)

2. Independent failure of a letdown valve (closed) and of both pressurizer PORVs, so they do not open to relieve RCS pressure.

2.6.4 Reactor Coolant System Overpressure Sequence Number 2

This transient is initiated when the reactor is being heated up from cold shutdown. The RCS temperature is near 350°F and the pressure is approximately 250 psig. At this point in the heatup procedure the pressurizer PORVs are

shifted from the "low temperature" to the "normal" position and the ECCS systems are enabled. The failure mode that causes the transient is an inadvertent SI initiation. The failure mechanisms that could cause this failure mode to occur are:

1. A single logic circuit failure results in actuation of the safeguards sequence.

2. Independent failures that initiate high head safety injection flow and opening of the accumulator isolation valves.

3. A single failure in one of the two safety injection actuation push buttons that results in actuation of the safeguards sequence.

2.6.5 Steam Generator Overfill Sequence Number 1

The failure mode for this scenario is high main feedwater flowrate. The failure mechanisms that could cause a high main feedwater flowrate are listed below. Main feedwater increased the level to the high level setpoint which then trips the main feedwater pumps and starts the auxiliary feedwater pumps which increases the level beyond that point.

1. A failure occurs in the controlling SG level instrument causing a false low level signal and an increased main feedwater flowrate. (This failure mechanism is not applicable during low power operation when feedwater flow is being controlled manually utilizing the bypass valves.)

2. A leak occurs in the sensing line to the controlling SG level instrument causing a false low level signal and an increased main feedwater flowrate. (This failure mechanism is not applicable during low power operation when feedwater flow is being controlled manually utilizing the bypass valves.)

3. A malfunction of the feedwater regulating valve causes it to open resulting in an increased main feedwater flowrate.

4. The steam generator water level controller suffers a failure that results in an increased flow signal to the feedwater regulating valve causing it to open.

2.6.6 Steam Generator Overfill Sequence Number 2

This transient is initiated by a high main feedwater flow failure mode and is either accompanied with or followed by a failure of the high steam generator level trip while not initiating a low steam generator level reactor trip. The failure modes identified result in an increase in feedwater flow rate with a simultaneous or subsequent steam generator high level trip failure. The failure mechanisms that could cause this failure mode are:

1. A failure occurs in the controlling SG level instrument causing it to indicate low with a concurrent or subsequent second level channel sticking or failing as is.

2. A leak occurs in the sensing line to the controlling SG level instrument and a second level instrument sticks or fails as is.

3. A malfunction of the feedwater control valve causes it to open and two out of three SG water level instruments fail to increase to the high level trip point.

4. The steam generator water level controller fails with an increased flow demand output and two out of three SG water level instruments fail to increase to the high level trip point.

5. The controlling SG level instrument fails low and the high SG water level trip circuitry or trip device fails to stop main feedwater flow.

6. A leak in the sensing line to the controlling SG water level instrument causes it to fail low and the high level trip circuitry or trip device fails.

7. The feedwater control valve fails open and the high level trip circuitry or trip device fails to stop main feedwater flow.

8. The steam generator water level controller fails with an increased flow demand and the high level trip circuitry or trip device fails.

2.6.7 Steam Generator Tube Rupture Sequence Number 1

For the steam generator tube rupture scenarios, a tube rupture is a given event that occurs to initiate the transient. The failure modes discussed are aggravating failures that are analyzed in an attempt to increase the severity of the transient. No control system failures have been identified that could cause the tube rupture itself.

This sequence aggravates the tube rupture with a failure of a steam line safety valve or PORV for the steam generator with the tube rupture, which provides a leakage path for the reactor coolant directly to the atmosphere. A loss of offsite power is also postulated which would have the following effects on contributor systems: (a) loss of reactor coolant pump flow, (b) loss of charging and letdown flow, (c) loss of main feedwater flow, (d) start of the auxiliary feedwater pumps, (e) loss of main condenser vacuum due to a loss of evacuation pumps and circulating water flow, and (f) loss of steam dump flow due to low condenser vacuum. The failure mechanisms that could cause a safety valve or PORV to stick open are discussed below. Individual failure mechanisms for a loss of offsite power are not identified here, since separate studies have been performed on this failure mode and a probability of its occurrence has been calculated. There are no common mode failures between the loss of offsite power and inadvertent operation of a safety valve or PORV. The safety valve/PORV failure mechanisms are:

1. Failure of a component in the steamline PORV control circuit causes the valve to open and remain open.

2. A mechanical failure of a PORV causes it to stick open.

3. Failure of a component in the steam dump controller causes a steamline PORV to open and remain open.

4. A mechanical failure of a safety valve causes it to stick open.

2.6.8 Steam Generator Tube Rupture Sequence Number 2

Steam Generator Tube Rupture Sequence Number 2 is initiated at 102% power and is aggravated with the following failure modes: high feedwater flow, and stuck open steamline PORV or safety valve (for the steam generator with the ruptured tube). The feedwater flow was failed high in an attempt to take the steam generator water solid and discharge two phase flow (water/steam mixture) or water out of the steamline PORV or safety valve. Discharging saturated steam or water out a PORV/SRV could result in discharging the radioactive isotopes that are partitioned in the secondary water to the atmosphere, thereby possibly increasing the offsite radioactive release. The failure mechanisms for high feedwater flow are the same mechanisms as listed in Section 2.6.5 for Steam Generator Overfill Sequence Number 1. The failure mechanisms for the safety valve or PORV sticking open are the same mechanisms as listed in Section 2.6.7 for Steam Generator Tube Rupture Sequence Number 1. There are no direct common mode failures for these two failure modes; however, there is a possibility that the steam generator overfill which was aggravated by the high feedwater flowrate could result in a water slug being discharged out of a steamline safety valve or PORV which could damage the valve so it would remain open. It is beyond the scope of this task to determine the probability of this postulated water slug-damage scenario, however, this analysis shows that an overfill condition did occur.

2.7 Sequence Probability Analysis

A probability analysis was performed to determine the likelihood of the sequences discussed in Section 2.6. Each sequence was assumed to be initiated from worse-case plant operational conditions and is discussed below along with the assumptions used in the analysis. The MOCARS computer code,[13] using Monte Carlo simulation to find the distribution of a function of random variables, was used to calculate the probability for each sequence.

2.7.1 Reactor Coolant System Overcool Sequence Number 1

For this event it is assumed that the plant is operating at 102% full reactor power and all control systems are controlling normally in the automatic mode. Reactor power is assumed to be 102% so that the initiating event, inadvertent opening of the steam dump valves, results in a reactor trip. If a lower initial reactor power had been assumed, the reactor would remain critical, and due to inherent feedback mechanisms, make it impossible for any feasible system failure to cause a rapid RCS cooldown.

The failure rates of interest for this event are a failure of a reactor T_{ave} temperature instrument and a failure of any one of four solid state control elements in the steam dump controller. The failure rates used and their source are shown in Table 10.

It was assumed that the plant is operating at full power 80% of the time during the year. Therefore, the calculation was made based on these conditions existing for 7008 h per year.

The median probability of failure for this sequence calculated by MOCARS is 6.7E-2 per reactor year with an upper bound of 2.6E-1.

TABLE 10. COMPONENT FAILURE RATES

Failure	Failure Rate	Error Factor	Source
Air Operated Valves Failure to remain open	3.0E-7/hour	100	IEEE-500[14]
Switch Contacts Short across normally open or normally closed contact	1.0E-8/hour	10	WASH-1400[15]
Relays Short across normally open or normally closed contacts	1.0E-8/hour	10	WASH-1400
Wires Short to power Line to line (power circuit)	1.0E-6/hour	3	IEEE-500
Motor Starter Spurious operation	2.0E-7/hour	10	IEEE-500
Solid State Devices Fails to function	1.0E-6/hour	10	MIL-HDBK-217C[16]
Electrical Bus Power failure	1.0E-8/hour	3	NREP Data Base[17]
Relief Valves Premature open	1.0E-5/hour	3	WASH-1400
Pipe Rupture (<3 in.) Per 12 ft section	1.0E-9/hour	10	NREP Data Base
Level sensors For control sensor and one of two trip sensors[a]			
Inoperability	2.6E-9/hour	3.5	NUREG/CR 3289[18] Common Cause Fault Rates for I&C
Reduced capability	3.1E-7/hour	5.2	NUREG/CR 3289 Common Cause Fault Rates for I&C

TABLE 10. (continued)

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a. NUREG/CR-3289, pp. C44 and C45, gives common cause fault rates for level sensors. Separate numbers are given for inoperability (spurious signal or no signal) and for reduced capability (out of calibration). Point estimates and upper bounds are given for $r_2 = \mu p^2 + \omega$ and for ω. Here, ω is the rate of lethal shocks causing all sensors to fail; and μ is the rate of nonlethal shocks making each sensor fail with some probability p. The relevant rate is the common cause failure rate for the control sensor plus one of the two trip sensors. This rate is $2\,\mu p^2 + \omega$. To approximate this number from the published numbers, the following formulas were used:

$2(r_{2,\text{point}} - \omega_{\text{point}}) + \omega_{\text{point}}$ for the point estimate, and

$2(r_{2,\text{upper}} - \omega_{\text{point}})$ for the upper bound.

This formula for the upper bound is conservative.

2.7.2 Reactor Coolant System Overcool Sequence Number 2

For this event it is assumed that the plant is shutdown, the average temperature is 547°F, the RCPs are operating, and all control systems are in automatic except rod control, pressurizer pressure control, and turbine control. The initiating event can be a failure open of one or more steam dump valves, one or more steamline PORVs, or the turbine control valves.

The failures of interest for this sequence are:

1. A solid state device failure in the steam dump controller,
2. Inadvertent open of an air operated steam dump valve,
3. A failure in a steamline PORV control circuit,
4. Inadvertent open of the solenoid and air operated PORV,
5. A failure of a solid state device in the turbine EHC, and
6. A failure of the hydraulically operated turbine governor valve to the open position.

It was assumed that the plant would be in the hot shutdown condition required for this sequence 876 h per year. This is based on the assumption that there will be 20 plant shutdowns power per year and this necessary condition will exist approximately 44 h per shutdown.

The median probability of failure for this sequence is 1.6E-2 per reactor year with the upper bound of 4.0E-2 per reactor year.

2.7.3 Reactor Coolant System Overpressure Sequence Number 1

For this event it is assumed that the plant is shutdown, the RCS temperature is 100°F, the RCS pressure is 350 psig, the pressurizer is water solid, and all RCPs are off. The failure mode for this scenario is a

loss of letdown flow coupled with a failure of both pressurizer PORVs. The failure of one PORV and the letdown valve could be caused by the failure of the power supply that is common to the two valve control circuits.

The failures of interest for this event are loss of a DC power supply, failure to open on demand of a PORV, and failure closed of an air operated letdown valve.

It was assumed that the cold shutdown plant conditions required for this sequence exist 876 h per year. This is based on the assumption that there will be 12 cold shutdowns per year and the low temperature conditions are assumed to exist 73 h per cold shutdown.

The pressurizer PORVs were assumed to be tested once every six months. Although the test frequency is each cold shutdown and cold shutdowns normally occur more frequently than every six months, this frequency was chosen to insure conservatism in the calculation.

The median probability of failure for this sequence is 7.7E-7 per reactor year with the upper bound of 8.2E-6 per reactor year.

2.7.4 Reactor Coolant System Overpressure Sequence Number 2

For this event it is assumed that the plant is shutdown, the RCS temperature is 350°F, the RCS pressure is 250 psig, all RCPs are operating, and there is a vapor volume in the pressurizer. A failure occurs that results in an inadvertent initiation of the Emergency Core Coolant System (ECCS) which results in an injection into the RCS from the accumulators and the SI pumps.

The failures of interest for this event are a malfunction of a solid state logic circuit in the safeguards actuation circuitry, inadvertent open of the motor operated accumulator isolation valves, a failure in the high head SI pumps control circuit, and a failure of a manual safety injection actuation push button.

It was assumed that there are six different logic circuits whose failure could result in an inadvertent safeguards actuation signal. The logic circuits involved are the two out of three circuits for high steamline flow, low pressurizer pressure, high steamline differential pressure, and high containment pressure; and the OR logic circuits that monitor the output of the two out of three circuits discussed above.

There are two separate manual safety injection actuation pushbuttons and either pushbutton can cause an SI actuation to be initiated. Therefore, a failure probability for each pushbutton was used in the calculation.

It was assumed that the plant conditions required for this sequence exist 6 h per month or 72 h per year. This is based on the conservative assumption that there will be one cold shutdown per month and the appropriate conditions will exist 6 h during each cooldown and heat up cycle.

The median probability of failure for this sequence is 8.5E-4 per reactor year with the upper bound of 2.9E-3 per reactor year.

2.7.5 Steam Generator Overfill Sequence Number 1

For this event it is assumed that the plant is operating at 5% power. (Other computer calculations were performed for this failure mode using higher initial reactor power levels. Even though some of the evaluated failure mechanisms are not applicable at lower powers due to feedwater flow being controlled in manual utilizing the bypass valve, they would be applicable for higher initial power levels when the steam generator water level control would normally be in automatic control.) All system parameters are being controlled in their normal operating levels. A failure occurs that results in a feedwater control valve going to the fully open position.

The failures of interest for this event are a failure of the controlling SG level instrument, a pipe leak or rupture on the level transmitter sensing line, inadvertent open of an air operated control valve, and a failure of a circuit in the SG water level controller.

It is assumed that the level instruments are checked to verify proper operation every 8 h during plant operation.

The median probability of failure for this sequence is 1.9E-2 per reactor year with the upper bound of 1.2E-1 per reactor year.

2.7.6 Steam Generator Overfill Sequence Number 2

For this event it is assumed that the plant is operating at 67% power and all control systems are in automatic except the rod control system. A failure occurs that results in a high feedwater flow to one of the steam generators and a second failure prevents the high level trip from being actuated which permits the main feedwater flow to continue into the affected steam generator.

The failures of interest for this event are:

1. A failure low of a SG level instrument,
2. A failure as is of a SG level instrument,
3. A leak or rupture of a SG level transmitter sensing line,
4. Inadvertent open of the air operated control valve,
5. A circuit failure in the SG level controller, and
6. Failure of the high SG water level trip circuit.

Several of the failure mechanism sequences identified by the Mechanistic Failure Analysis (Section 2.6) would require the independent failure of two or three systems or components, which would result in a

negligible probability based on the failure rates shown in Table 10 and the periodic functional testing frequency of once every eight h during plant operation.

The median probability of failure for this sequence calculated by MOCARS is 2.2E-3 per reactor year with an upper bound of 1.1E-2 per reactor year.

2.7.7 Steam Generator Tube Rupture Sequence Number 1

For this event it is assumed that the plant is operating at 102% reactor power, the RCS pressure is 2280 psia, and all control systems are operating in automatic. For this event, a steam generator tube rupture is assumed to occur and the major focus of this study is the aggravating system failures. The aggravating failure modes for this sequence are failure of offsite power and a stuck open steamline PORV or safety valve.

The failures of interest for this event are a loss of offsite power, failure in the PORV control circuit, inadvertent open of an air operated PORV, failure of a control circuit in the steam dump controller, and inadvertent open of a safety valve.

It was assumed that the operating plant conditions for this sequence exist 7008 h per year, or 80% of the time.

The median probability of failure of the aggravator for this sequence is 2.9E-7 per reactor year with the upper bound of 3.5E-6. The above numbers are not the the probability of the entire sequence, but are only for the aggravating system failures since the steam generator tube rupture was assumed as a given event. An approximation (based upon a hand calculation instead of a MOCARS calculation) of the overall sequence probability is ~2E-8 per reactor year with an upper bound of ~2E-7. These figures are based on a heat exchanger tube leak probability of 1×10^{-9}/h per tube[17] (a frequency of $\sim 7 \times 10^{-2}$ per reactor year given 3 steam generators and 3260 tubes/steam generator) and would, therefore, be conservative for a tube rupture.

2.7.8 Steam Generator Tube Rupture Sequence Number 2

The plant conditions for this event are the same as those for Steam Generator Tube Rupture Sequence Number 1 above. The aggravating system failures that occur with the tube rupture are a high feedwater flow to the affected steam generator and inadvertent open of a steamline PORV or safety valve.

The failures of interest for this event are:

1. A failure of a steam generator level instrument,

2. A pipe leak or rupture on the level transmitter sensing line,

3. Inadvertent open of an air operated control valve,

4. A circuit failure in the SG water level controller,

5. Failure in a PORV control circuit,

6. Inadvertent open of the air operated PORV,

7. A circuit failure in the steam dump controller, and

8. Inadvertent open of a safety valve.

The median probability of failure of the aggravators for this sequence is 4.3E-6 per reactor year with an upper bound of 4.8E-5 per reactor year. Again, these numbers do not represent the probability of the entire sequence, but are only for the aggravating system failures and do not include the tube rupture itself. An approximation of the overall sequence probability is ~3E-7 per reactor year with an upper bound of ~3E-6 per reactor year.

3. OPERATOR ACTION EVALUATION

Each of the event scenarios that resulted in exceeding a selection criteria was further analyzed to determine the expected ability of the operators to recognize the event and take appropriate action to mitigate the event. As stated in Section 2.5, in keeping with the proposed guidelines in ANSI Standard N660, no credit was taken for operator actions in these sequences until 10 min after the initiating event. However, the analysis indicates that there are some of the events where there is a possibility for the operators to recognize the event and take corrective actions prior to exceeding the appropriate selection criterion.

3.1 Reactor Coolant System Overcool Sequence Number 1

The plant status for this evaluation is: the reactor is at 102% full power and all control systems are in automatic. A failure occurs in the steam dump controller which causes all steam dump valves to open, thereby increasing the steam flow and power.

The operator would be alerted to the transient by several alarms such as: $T_{ave} - T_{ref}$ mismatch and feed flow-steam flow mismatch, which would occur almost immediately, and MFW pump trip, turbine trip, and reactor trip, which would be actuated after approximately 2 s. But, there would be no alarms received that would directly indicate that the increased steam flow is due to a steam dump malfunction. There would be some indication (without alarms) on the steam dump status panel. As the temperature decreased, the low-low T_{ave} alarm would be actuated alerting the operator to a continuing temperature decrease.

H. B. Robinson does not have any specific procedures that cover a failure open of the steam dump valves. However, this transient would appear to be a steamline break and there is an Emergency Instruction[19] that addresses steamline ruptures. In Appendix B of E.I.-1, the operator is instructed to close the MSIVs which would isolate steam flow to the steam dump valves. If this scenario were assumed to occur, the plant cools down 100°F in approximately 125 s.

3.2 Reactor Coolant System Overcool Sequence Number 2

The plant status for this evaluation is: the reactor is in hot shutdown during a startup or shutdown evolution, the RCS temperature is approximately 547°F and three RCPs are operating. A control system failure results in the three steamline PORVs opening and remaining open.

The operator would be able to recognize this abnormal occurrence by the steamline PORV open indication and by observing an increase in steam flow. Shortly after the initiation a low-low T_{ave} alarm will be actuated and the safety injection actuation system (SIAS) with its accompanying alarms will be initiated at 14.9 s.

There were no abnormal operating or emergency procedures found to give direction in mitigating this event. There are no isolation valves for the steamline PORVs and it would require several minutes to perform the SI actuation verification and the SI termination procedures. If this scenario were assumed to occur, the plant cools down 100°F in 230 s.

3.3 Reactor Coolant System Overpressure Sequence Number 1

The plant status for this evaluation is: the reactor is in a cold shutdown mode, the RCS temperature is 100°F, the RCS pressure is 350 psig, the RCS is water solid, and all RCPs are off. A power supply failure simultaneously de-energizes the letdown valve and a pressurizer PORV, causing the letdown valve to fail closed and a single PORV to become inoperable. The resultant transient is then aggravated by a failure to operate of the second pressurizer PORV.

The operator would be alerted to the transient by the low temperature-high pressure alarm unless the initiating and aggravating failures had also disabled the alarm. There are also other indications of this transient such as an increasing RCS pressure and no letdown flow.

There were no procedures or cautions found to mitigate this condition. The operator could terminate this transient by shutting off the charging pumps, but he would have only 15 s to recognize the problem and do so prior to exceeding the 440 psia 10 CFR 50, Appendix G[10] curve limit for a 100°F RCS temperature.

3.4 Reactor Coolant System Overpressure Sequence Number 2

The initial plant status for this evaluation is: the reactor is shutdown in the process of being heated up, the RCS temperature is 350°F, RCS pressure is 250 psig, all RCPs are operating, and there is a vapor volume in the pressurizer. After having switched the pressurizer PORV permissive switches from the "low temperature" to the "normal" position (step 4.30.2 in General Procedure[20] GP-2), a failure in the SIAS circuitry results in a spurious SI actuation signal. The SIAS results in an injection into the RCS by the accumulators and the high head safety injection pumps.

The operator would be alerted to the transient by the alarms and indications associated with the SI actuation. Following are some of the indications that would be received: phase "A" isolation, starting of safeguards trains "A" and "B", reactor trip, turbine trip, starting of diesel generators "A" and "B", MFW pumps trip, and feedwater isolation valves trip.

H. B. Robinson has an Abnormal Operating Procedure[21] (A.P.-25) that covers spurious safeguards actuation. This procedure includes instructions for stopping the safety injection pumps which would mitigate the transient. However, the operator would not stop high head safety injection system until after he had performed his immediate actions of verifying the SI initiation per Emergency Instruction E.I.-1, and then carefully observing plant conditions to verify that the initiation was in fact spurious (per A.P.-25). If this scenario were assumed to occur, the pressure limit of 720 psi for an RCS temperature of 330°F would be exceeded in approximately 162 s.

3.5 Steam Generator Overfill Sequence Number 1

The plant status for this evaluation is: the reactor is at 5% power (Other computer calculations were performed for this failure sequence using higher initial reactor power levels. It was found that SG overfill will occur at the higher power levels, however, it requires more time. It should be noted that at low power levels, the feedwater flow would normally be controlled in manual on the bypass valve, which would restrict the failure mechanisms that could possibly cause this transient.) All controls are in automatic except for feedwater control and rod control. A failure occurs in the feedwater control valve that cause it to fully open. When the SG narrow range reaches 75% (the high level trip), the main feedwater pumps are tripped off which results in automatic initiation of the motor driven auxiliary feedwater pumps.

The operator would be alerted to the transient by several alarms such as steam flow-feed flow mismatch and high-low steam generator level. Later in the transien., after the steam generator high level setpoint is reached, the operator will have the following indications: turbine trip, MFW pumps trip, motor driven auxiliary feedwater (MAFW) pumps start, and a high level indication on two out of the three SG level instruments.

No procedures were noted that specifically address this transient. The operator could terminate this transient by turning off the MFW pumps and then throttling the auxiliary feedwater control valves to maintain SG level in the control band. The initial conditions for this event would only be encountered during plant startup or shutdown, where it is anticipated that there would be increased surveillance of plant parameters by the operator. 205 s are required before there is a significant decrease in steam quality.

3.6 Steam Generator Overfill Sequence Number 2

The plant status for this evaluation is: the reactor is at 67% power and all control systems are in automatic except the rod control system. A failure occurs in the controlling steam generator level instrument causing

the controller to increase feedwater flow to maximum for that steam generator. A second level instrument for the affected steam generator fails as is.

The operator would be alerted to the transient by the following alarms: steam flow-feed flow mismatch and high-low steam generator level. Since two of the three steam generator level instruments do not respond correctly, there will be no trips or alarms when the level reaches the high level setpoint.

No procedures were noted that specifically address this transient. The operator could terminate this transient by selecting the backup level instrument as the controlling instrument, or by securing the MFW pumps and throttling the AFW pump control valves. However, the confusion factor is increased by the failure of the second level instrument, and the time available for recognition of the failure and for taking corrective action is significantly reduced (liquid carryover begins at 20 s).

3.7 Steam Generator Tube Rupture Sequences Number 1 and 2

The two steam generator tube rupture events are discussed together since the initiating event (tube rupture) and operator response are nearly identical. The plant status for these evaluations is: reactor power is 102%, RCS pressure is 2280 psia, and all control systems are operating in automatic. The initiating event is a complete tube break adjacent to the tube sheet. Both scenarios assume an aggravating failure of a steamline PORV in the open position. Steam Generator Tube Rupture Sequence Number 1 also assumes a loss of offsite power and Steam Generator Tube Rupture Sequence Number 2 assumes a high feedwater flowrate to the affected steam generator.

The operator would be alerted to the transient by several alarms such as: pressurizer low pressure, pressurizer low level, condenser air removal equipment high radiation, steam generator blowdown high radiation, main

steam line high radiation, SIAS, reactor trip, and turbine trip. It would be readily apparent that the basic problem is a loss of coolant accident (LOCA); however, it may take a few minutes to identify the specific location of the break.

H. B. Robinson has Emergency Instruction-1 (E.I.-1) covering incidents involving RCS depressurization. Appendix C to E.I.-1 is a detailed recovery procedure for a steam generator tube rupture. For the computer analysis, the operator actions identified in Appendix C were performed starting with the first step at 10 min and completing a procedural step every minute until the calculation was terminated. In some cases, more rapid operator action could be expected, while in other cases more time would be required to complete the action. Given the postulated aggravating failures for these scenarios, it is not expected that operator action can preclude exceeding the appropriate selection criteria. Actual experience with steam generator tube ruptures at Prairie Island and Ginna have shown that the operators experienced difficulties in terminating the steam generator tube rupture break flow within the 30 min assumed in the FSAR analysis.[22,23]

4. GENERIC APPLICABILITY TO WESTINGHOUSE PWR PLANTS

The Westinghouse Electric Corporation, Water Reactor Division, is performing an evaluation to determine if the findings of this study are generically applicable to all Westinghouse PWRs. The Westinghouse evaluation is being performed under a separate contract with EG&G Idaho, Inc.

For the present time, the specific sequences identified in this study are considered to be generically applicable. Certain plant designs may preclude some or all of these sequences; however, the majority of operating Westinghouse PWRs have sufficient similarity in system design and operating parameters that the sequences identified in this study are considered to be applicable on a generic basis. Upon completion of the Westinghouse contract, this report will be revised and reissued incorporating the findings and conclusions of the Westinghouse evaluation.

5. INTERNATIONAL CRITERIA/PRACTICE FOR CONTROL SYSTEMS

The review of the international community control system criteria/practice was conducted as a single review that is applicable to all EG&G Idaho, Inc. USI A-47 studies. The review is repeated in this volume so that the main report volumes for each study will be complete.

The following summarizes foreign criteria/practice as it relates to control systems and compares it with that used in the United States. Since the criteria/practice for control systems, protection systems, and accident analyses are often interrelated, the following touches on all of these areas as required to understand the basis for control system criteria/practice. The control system criteria/practice for Germany, Belgium, Italy, Spain, Switzerland, Britain, Canada, France, and Japan are discussed.

Although the foreign criteria/practice for control systems is interesting and sometimes different, the differences can not be considered as significant. Germany basically has three levels of systems for reactor protection, but control systems are used for normal operational transients and have similar design criteria to those in the United States. Canada requires complete separation between control and protection systems, but control systems are used to prevent fuel damage and protection systems are used to limit fuel damage. In the United States, control systems are not relied on to prevent fuel damage; the protection system is used to prevent fuel damage and engineered safeguards are used to limit fuel damage. The British tend to rely on numerical risk assessment and control system failures are included in the risk assessment. However, the British do not appear to have specific design requirements for control systems. The remaining countries tend to follow the United States practice, and may in some cases, include some of the German requirements/practices.

This summary of the foreign criteria/practice for control systems is based on information obtained from the Instrumentation & Control Systems Branch of the Nuclear Regulatory Commission.[24]

5.1 Germany

The primary function of the control systems is to control the plant during normal operation, including transients, to meet grid demands. In general, more separation between control and protection systems is required in Germany than in the United States. Separation between safety equipment and nonsafety equipment has apparently been carried to the point of using one set of valves to isolate feedwater and another set to control feedwater. However, the German safety standard for the reactor protection system and engineered safeguards does allow for the use of common measuring devices for control and reactor protection as is done in the United States. Since the Three Mile Island accident, additional startup testing and failure mode and effect analyses have been required to verify that control systems will not interfere with the operation or performance of the protection system.

The German safety standard for the reactor protection system and engineered safeguards does not cover controls and interlocks required during normal operations, nor does it cover "operational limitations" that are defined as devices that limit the value of process variables in order to increase plant availability. However, this standard does cover accident analyses and includes the requirement to consider potential control system failures. Normal steady-state operation is assumed as the initial plant condition for accident analyses but the German safety standard also requires that the most unfavorable plant operational state be considered. The basis for the most unfavorable plant operational state is steady-state operation plus possible deviations of process variables from required values due to a single random failure in the control system. It was not possible to determine exactly how this requirement has been applied, but it implies that the accident analyses should include an assumption that one controlled variable such as temperature (or pressure, flow, level, etc.) is significantly different than its normal operating value due to a single random failure in the control system. United States practice is to assume initial conditions are normal operating conditions with allowances for

measurement and control inaccuracies. A control system failure that would make the initial conditions more adverse would not be assumed in the United States.

The German safety standard for the reactor protection system and engineered safeguards does address two features that do not have exact counterparts in United States plants. These two features are not directly related to control systems but are discussed here for the purpose of identifying differences between the German and the United States philosophy on reactor protection. These two features are referred to as "protective limitations" and "condition limitations." "Protective limitations" are defined as devices that actuate protective actions to return a safety variable to its value specified for normal operations. Essentially, the same design criteria apply to "protective limitations" as apply to the reactor protection system, except that only one redundant set of signals is required for "protective limitations" whereas two diverse sets of signals with each set having redundancy are required for the reactor protection system. "Condition limitations" are defined as devices that limit the value of process variables such that initial conditions assumed for specified incident analyses are met. "Condition limitations" are required to be redundant and separate from each other and from operational systems.

The German philosophy has been described as consisting of "control systems," a "grey protection system," and a "black protection system." The "control systems" would be used for normal operational transients as in the United States and would have design criteria similar to those in the United States. The "grey protection system" would consist of reactor trips necessary to conservatively prevent fuel damage by maintaining design limits but it would also consist of such features as turbine runback and certain controls to reduce the need for reactor trips. The "black protection system" would include those reactor trips and engineered safeguards necessary to protect public health and safety.

5.2 Belgium, Italy, Spain

These countries follow the United States practice closely with, in some cases, additional German requirements.

5.3 Switzerland

The criteria in Switzerland tends to be a merger of the United States and German requirements.

5.4 Britain

In general, the British tend to approach reactor safety with more emphasis on numerical risk assessment. The British have a numerical reliability goal for certain control systems whose failure would challenge protection systems. Thus, control system failures would be included in the risk assessment.

The British document on safety assessment principles identifies two categories of systems provided to ensure nuclear safety. These categories are "protection systems" and "safety-related instrumentation." "Protection systems" are all equipment or systems that act directly in the event of faults to prevent damage that may lead to the release of radioactivity. "Safety-related instrumentation" is instrumentation having a significant but indirect effect on nuclear safety. "Safety-related instrumentation" consists of: (a) control systems whose failure can cause a demand on the protection system, (b) instrumentation used to warn of the onset of hazardous conditions or conditions requiring manual safety action, (c) instrumentation for monitoring the protection system, reactor, and plant variables, (d) communication equipment for accident conditions, and (e) equipment for monitoring abnormal radioactive releases from the site.

Thus, the British consider control systems whose failure can cause a demand on the protection system to be safety-related. In the United States, control systems are not classified as safety-related. However, the British document on safety assessment principles does not appear to provide a list of specific design requirements for control systems.

5.5 Canada

Complete separation between control and protection systems is required on Candu reactors. There is no sharing of components. Even separate control rods are used for control and protection action. Similar separation is required for engineered safeguards equipment.

The Canadians have limits on the number of demands per year placed on the protection system as a result of control system failures. A control system believed to be capable of meeting the failure rate criteria is designed, and its performance is monitored during subsequent plant operations. If the experienced failure rate (demands on the protection system) exceeds the design limit, the control system must be modified to reduce the failure rate to the acceptable value. Either more reliable components are used or the system configuration is modified. The limit on the number of demands per year on the protection system may require redundancy in some control features. Redundancy in itself, however, is not required.

The Canadian philosophy on the function of control systems, however, is different from that in the United States. The control system may perform functions such as running rods in at a high rate or tripping selected rods to prevent fuel damage. The protection system would not be required to prevent fuel damage but instead, would only be required to limit fuel damage. In the United States, the philosophy is to use the protection system to prevent fuel damage for anticipated operational occurrences and, with the engineered safeguards equipment, to limit fuel

damage for accidents. In the United States, the control systems are primarily used for normal plant operation including operating transients such as load changes to meet grid demand. Control systems are not relied on to prevent fuel damage in the United States.

5.6 France and Japan

The French and the Japanese follow the United States practice very closely.

6. REVIEW OF NRC REGULATIONS

A review was made of the Standard Format for Final Safety Analysis Report, Regulatory Guide 1.70 Rev 3 1978, and the Standard Review Plan (SRP), NUREG-0800 Rev 3 1984[25] to determine if these guidelines adequately address the limiting transients identified in this study.

SRP Section 15.1.3[3] addresses increase in steam flow transients.

SRP Section 15.1.4 addresses inadvertent opening of a steam generator relief or safety valve.

Branch Technical Position RSB 5-2[26] addresses overpressurization protection of pressurized water reactors while operating at low temperatures.

SRP Section 15.2.2 addressed overpressure protection.

SRP Section 15.1.2 addresses increases in feedwater flow transients.

A part of the acceptance criteria for these sections specifies:

> "An incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently."

Section 7.7[3] of the SRP specifies that an acceptance criterion applicable to the control systems not required for safety is General Design Criterion 13.[27] Criterion 13 states:

> "Instrumentation shall be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the

reactor coolant pressure boundary, and the containment and its associated systems. Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges."

A portion of the review procedures for control systems in Section 7.7 is as follows:

1. The review should confirm that the control systems satisfy the requirements of the acceptance criteria and the system design bases.

2. The review should confirm that the plant accident analysis in Chapter 15 of the safety analysis report (SAR) does not rely on the operability control system to assure safety.

3. The review should confirm that the safety analysis includes consideration of the effects of both control systems action and inaction in assessing the transient response of the plant for accidents and anticipated operational occurrences.

4. The review should confirm that the consequential effects of anticipated operational occurrences and accidents do not lead to control systems failures that would result in consequences more severe than those bounded by the analysis in Chapter 15 of the SAR.

5. The review should confirm that the failure of any control system component or any auxiliary supporting system for control systems do not cause plant conditions more severe than those bounded by the analysis of anticipated operational occurrences in Chapter 15 of the SAR. (The evaluation of multiple independent failures is not intended.)

Thus, the existing criteria specified in Sections 7 and 15 of the SRP provide adequate guidance and acceptance criteria that, if strictly applied would preclude the existence of the potential limiting transients identified in this study.

SRP Section 15.6.3 addresses radiological consequences of steam generator tube failure (PWR).

A steam generator tube rupture is a Design Basis Accident (DBA) and as such the acceptance criteria is based on radiological offsite dose rates.

The scenarios identified by this study assumed the tube rupture had occurred and was then aggravated by a control system failure, i.e., PORV opens and fails to close.

A portion of the review procedures in Section 15.6.3 is as follows:

1. Review of the applicant's description of the tube failure accident, with and without offsite power. This includes a review of the sequence of events, the bases for the occurrence, and assurance of an adequate degree of conservatism.

2. Review of the signals available to the reactor operator that indicate the occurrence of the accident and the state of the system throughout the recovery period. Automatic and required manual operations by the operator as a function of time are reviewed. The Accident Evaluation Branch (AEB) reviewer verifies with the Reactor Systems Branch (RSB) the acceptability of the applicant's description of events, including operator actions, to assure that the most severe case has been considered with respect to the release of fission products and calculated doses.

Therefore, the existing criteria specified in Sections 7.7 and 15.6.3 of the SRP provide adequate guidance and acceptance criteria that, if strictly applied would preclude the potential of the worst case DBA identified in this study.

Since the existing criteria addressed the identified sequences, the criteria were judged to be adequate and no revisions or additions are recommended.

7. RESULTS, CONCLUSIONS, AND RECOMMENDATIONS

The study results, conclusions and recommendations are discussed in the following sections.

7.1 Results

This study identified certain system failures that could cause reactor coolant overcool (cooldown rate of greater than 100°F/hr), reactor coolant system overpressurization at low temperatures, steam generator overfill and control system failures that would cause a tube rupture accident to be more severe than previously analyzed.

The sequences identified are:

1. Reactor Coolant System Overcool

   Sequence 1--Failures that result in steam dump system actuation.

   Sequence 2--Failures that result in steamline relief valve (PORV) actuation during hot shutdown conditions.

2. Reactor Coolant System Overpressurization While At Low Temperature

   Sequence 1--Failures that result in isolation of letdown flow and simultaneously disable one of two pressurizer PORVs, aggravated by failure of the second PORV.

   Sequence 2--Failures that result in inadvertent ECCS initiation shortly after the low temperature overpressure protection (LTOP) system setpoint has been reset to the normal relief setpoint.

3. Steam Generator Overfill

Sequence 1--Failures that result in full feed flow being delivered to a steam generator while at low power levels. The feed pump high level trip is assumed to function. Following the high level trip, the auxiliary feedwater system overfills the steam generator.

Sequence 2--Failures that result in a high feed flow rate with simultaneous or subsequent high level trip failure.

4. Steam Generator Tube Rupture

The following sequences assume a steam generator tube rupture has occurred. The identified sequences indicate failures capable of aggravating a steam generator tube rupture accident.

Sequence 1--Assuming a steam generator tube rupture has occurred with a concurrent loss of offsite power, failures that result in steamline relief (PORV) of safety valve failing in the open position.

Sequence 2--This sequence is similar to steam generator tube rupture Sequence 1 with the exception of the loss of offsite power. This sequence assumed offsite power was available. This sequence is aggravated by a continued excess feed rate and failure of a steamline PORV or safety valve.

All other accident and transient sequences were shown to be bounded by the H. B. Robinson Unit 2 FSAR analysis.

The failure mechanisms capable of causing the above system failures were identified and sequence probabilities were calculated. The sequence probabilities are, respectively:

Reactor Coolant System Overcool

Sequence 1	6.7E-2	Per reactor year median value
	2.6E-1	Per reactor year upper bound
Sequence 2	1.6E-2	Per reactor year median value
	4.0E-2	Per reactor year upper bound

Reactor Coolant System Overpressurization While At Low Temperature

Sequence 1	7.7E-7	Per reactor year median value
	8.2E-6	Per reactor year upper bound
Sequence 2	8.5E-4	Per reactor year median value
	2.9E-3	Per reactor year upper bound

Steam Generator Overfill

Sequence 1	1.9E-2	Per reactor year median value
	1.2E-1	Per reactor year upper bound
Sequence 2	2.2E-3	Per reactor year median value
	1.1E-2	Per reactor year upper bound

Steam Generator Tube Rupture (Note: These Probabilities assume that a tube rupture has occurred)

Sequence 1	2.9E-7	Per tube rupture event median value
	3.5E-6	Per tube rupture event upper bound
Sequence 2	4.3E-6	Per tube rupture event median value
	4.8E-5	Per tube rupture event upper bound

These sequences were examined to determine if operator action could be assumed to terminate these transients or accidents. Early recognition of the transient or accident is necessary since none of the sequences take

longer than 10 minutes to lead to the undesirable conditions. Given early recognition, there are actions that the operator could take to mitigate these transients or accidents and these operator actions are documented in Section 3. However, for the purposes of this study the proposed ANSI Standard N660, which assumes no operator action within the first 10 minutes, was followed. Therefore, no operator action was assumed.

For this PWR review no effort was made to determine if these sequences of concern are applicable to Westinghouse reactor plants on a generic basis. A separate subcontract was initiated with the Westinghouse Electric Corporation Water Reactor Divisions to perform an evaluation to determine if the findings of this study are applicable to Westinghouse Plants on a generic basis.

The Westinghouse evaluation will be completed at a later date. Following receipt of the results of the Westinghouse evaluation, this report will be amended or revised as required if the results of their evaluation have any impact on the results, conclusions or recommendations presented in this report.

The NRC criteria pertaining to control systems and accident analysis were reviewed to determine if the applicable criteria adequately addressed control system failures. Since the existing criteria addressed the identified sequences, the criteria were judged to be adequate and no revisions or additions were recommended.

A review of recorded plant occurrences for the H. B. Robinson Nuclear Plant (for years 1980-1982) was conducted to determine if nonsafety grade control system failures had:

1. Detrimentally affected operator action,

2. Caused unwarranted challenges of safety systems,

3. Caused transients to occur at an unacceptable frequency, or

4. Caused Technical Specifications Safety Limits to be exceeded

Of the plant occurrences reviewed none were found that resulted in the above items.

7.2 Conclusions

With the exception of the identified sequences that result in steam generator overfill, reactor coolant system overcool, low temperature overpressurization and failures which are capable of aggravating a steam generator tube rupture, all other postulated sequences were shown to be bounded by the analyses in Chapter 15 of the H. B. Robinson Unit 2 FSAR. The H. B. Robinson plant design provides adequate redundant safety grade systems to mitigate the effects of all other transients and accidents.

The identified sequences that result in steam generator overfill and reactor coolant system overcool transients were evaluated to determine if they complied with the SRP acceptance criteria. Based on the concerns related to steam generator overfill transients, it cannot be verified that the postulated sequences comply with the Chapter 15 acceptance criteria which states, "An incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently."

The concerns for steam generator overfill transients include static loading of the steam line piping, water slug and water hammer loadings, and the possibility that safety related equipment, such as the safety valves and the turbine driven auxiliary feed pump which are connected to or interface with the main steam system, may be damaged or fail to perform their intended functions under steam generator overfill conditions.

The overcool concerns are related to exceeding Technical Specification limits associated with the 10 CFR 50 Appendix G requirements.

Similarly the concerns related to the low temperature overpressurization sequences are related to exceeding the technical specifications limits associated with the 10 CFR 50 Appendix G requirements.

The steam generator tube rupture aggravating sequences, identified failures, which if assumed to occur, would result in more radioactively contaminated mass being discharged to the atmosphere than was assumed in the FSAR analysis.

7.3 Recommendations

The following items are recommended for NRC staff consideration.

1. This study utilized the general guidance of 10 minutes for operator action. Three of the identified sequences were assumed to occur during startup or shutdown evolutions. These evolutions are normally performed under controlled conditions; therefore, based on the available alarms, indications, and actions required, it may be judged reasonable to assume operator action in less than 10 minutes. However, this is considered a licensing decision which will require NRC staff input.

2. Since this study identified sequences which could result in steam generator overfill and reactor coolant system overcool, the staff should consider initiating a study to address the consequences and risk associated with overfill and overcool events. Consequences of cooldown rates greater that 100°F/hr may be included in the A-49, Pressurized Thermal Shock Study.

3. Two of the identified sequences are concerned with low temperature overpressurization. Overpressure Sequence 2 is assumed to occur during startup evolutions and should be considered in Recommendation 1 above. The first overpressure sequence has a calculated median probability of 7.7E-7 with an upper bound of 3.2E-6. These probabilities are considered to be

very low and are several orders of magnitude less than the proposed safety goals of less than 1.0E-4. As in Recommendation 1, decisions based on probabilities are licensing decisions which will require NRC staff input.

4. The tube rupture sequences were also calculated to have a very low probability of occurrence (median estimates of 2.9E-7 and 4.3E-6). These probabilities do not include the probability of a steam generator tube rupture occurring. When combined with estimates of a tube rupture occurring, these sequence probabilities are extremely low.

The tube rupture sequences do, however, have the potential for direct offsite release and therefore, should be reviewed by the NRC staff.

The Westinghouse Electric Corporation, Water Reactor Division, is performing an evaluation to determine if the findings of this study are generically applicable to all Westinghouse PWRs. The Westinghouse evaluation is being performed under a separate contract with EG&G Idaho, Inc. Upon completion of the Westinghouse evaluation, that evaluation will require a review to determine if it adequately addresses the generic aspects of this study.

Pending resolution of these items, the results of this study should be considered along with other studies being performed relating to this issue to formulate a position for resolution of unresolved Safety Issue A-47.

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AUGUST 1984

EFFECTS OF CONTROL SYSTEM FAILURES ON TRANSIENTS AND ACCIDENTS AT A 3-LOOP WESTINGHOUSE PRESSURIZED WATER REACTOR

APPENDIX A - FAILURE MODE AND EFFECTS ANALYSIS (FMEA) TABLES
APPENDIX B - DETAILED H. B. ROBINSON UNIT 2 COMPUTER MODEL DESCRIPTION
APPENDIX C - SCENARIO COMPUTER ANALYSIS AND EFFECTS

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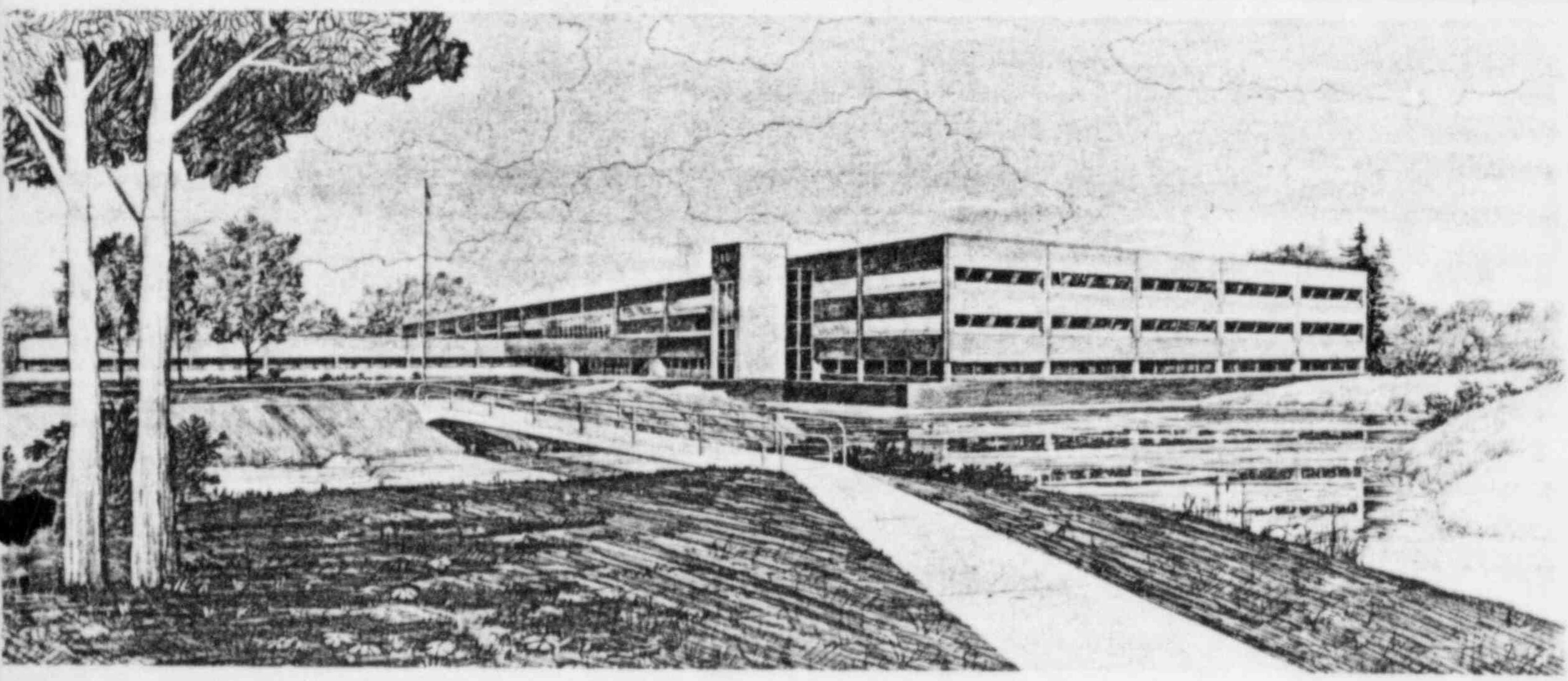
Operated by the U.S. Department of Energy



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FOREWORD

Safety Implications of Control Systems (A-47) was approved as an Unresolved Safety Issue (USI) by the Nuclear Regulatory Commission (NRC) in December of 1980. USI A-47 is concerned with the potential for transients or accidents being made more severe than previously analyzed as a result of control system failures. This report describes the work performed on the effects of control system failures on transients and accidents at a Westinghouse 3-loop pressurized water reactor. This work was conducted for the U. S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Division of Safety Technology by EG&G Idaho, Inc. and is based on the H. B. Robinson, Unit 2, Nuclear Plant.

This report is contained in two volumes: a main report and three appendices. The main report describes the study methodology, the major areas of work performed, and the results and conclusions. The appendices contain detailed information consisting of a detailed description of the computer model, and the deterministic computer analyses.

Numerous acronyms are used in this report. For each volume, these acronyms are defined in a listing immediately following the table of contents.

The U. S. Nuclear Regulatory Commission funded this work under authorization B&R 20-19-50-51-5, FIN No. A6477.

NOMENCLATURE

AFW	Auxiliary feedwater
ANS	American Nuclear Society
ASME	American Society of Mechanical Engineers
BOC	Beginning of cycle
BOL	Beginning of life
CVCS	Chemical and volume control system
DBA	Design basis accident
DECLG	Double-ended cold leg guillotine
DNB	Departure from nucleate boiling
DNBR	Departure from nucleate boiling ratio
ECCS	Emergency core cooling system
ENC	Exxon Nuclear Company
EOC	End of cycle
EOL	End of life
FMEA	Failure mode and effects analysis
FSAR	Final safety analysis report
HBR	H. B. Robinson

HPI	High pressure injection
LHGR	Linear heat generation rate
LOCA	Loss of coolant accident
LPI	Low pressure injection
LPSI	Low pressure safety injection
MAFW	Motor-driven auxiliary feedwater
MDNBR	Minimum departure from nucleate boiling ratio
MFW	Main feedwater
MSIV	Main steam isolation valve
MTC	Moderator temperature coefficient
NR	Narrow range
NSSS	Nuclear steam supply system
PCT	Peak cladding temperature
PLCS	Pressurizer level control system
PLS	Plant limitations and setpoints
PORV	Power operated relief valve
PPCS	Pressurizer pressure control system
PTS	Pressurized thermal shock

PWR	Pressurized water reactor
RCCA	Rod cluster control assembly
RCP	Reactor coolant pump
RCS	Reactor coolant system
RELAP5	Reactor excursion and leak analysis program version 5 which is a deterministic thermal-hydraulic analysis computer code
RHR	Residual heat removal
RPS	Reactor protection system
SAFW	Steam-driven auxiliary feedwater
SDCS	Steam dump control system
SDS	Steam dump system
SG	Steam generator
SGA	Steam generator A
SGLCS	Steam generator level control system
SI	Safety injection
SIAS	Safety injection actuation signal/system
SIS	Safety injection signal/system
SRP	Standard review plan
USI	Unresolved safety issue

APPENDIX A

FAILURE MODE AND EFFECTS ANALYSIS (FMEA) TABLES

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TABLES

EFFECTS OF CONTROL SYSTEM FAILURES ON TRANSIENTS AND ACCIDENTS AT A 3-LOOP WESTINGHOUSE PRESSURIZED WATER REACTOR

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FAILURE MODE AND EFFECTS ANALYSIS (FMEA) TABLES

A.1 GENERAL DISCUSSION

A failure mode and effects analysis (FMEA) was used in this study as a screening method to determine if nonsafety grade control system failures or misoperation have the potential to cause, contribute to, or aggravate transients or accidents to the point where these transients or accidents are more severe than previously analyzed in Chapter 15 of the H. B. Robinson Final Safety Analysis Report (FSAR).[1] The FMEA technique was the screening method chosen to determine if any of the first eight Selection Criteria (see Section 2.1) are potentially exceeded. An FMEA assumes that a failure has occurred and then examines the effects of that failure.

Since the effects of nonsafety grade control system failures are of primary interest for this study, the failure modes of interest would normally be at the control level, that is, the failure of control systems to perform their intended function such as controlling pump speed, valve position, etc. However, due to the numerous failure possibilities, a screening method was first used based on defining the failure modes as system failures rather than control level failures. In other words, the systems considered were assumed to fail in extreme operational conditions, such as full flow and no flow, inadvertent system operation and failure to operate, etc.

Each system failure mode is evaluated against the events of concern listed below:

1. Reactor coolant system overcool

2. Increase in reactor coolant system pressure

3. Positive reactivity increase

4. Increase in reactor coolant system inventory

5. Decrease in reactor coolant system flow

6. Decrease in reactor coolant system inventory

7. Steam generator overfill

8. Steam generator tube rupture.

Steam generator overfill, which would normally be a part of reactor coolant system overcool, and steam generator tube rupture, which would normally be a part of the decrease in reactor coolant inventory event, were treated in this study as additional events of concern. Even though steam generator overfill and steam generator tube rupture will contribute to their parent events (reactor coolant system overcool and decrease in reactor coolant inventory, respectively), there are specific concerns associated with the steam generator overfill and the steam generator tube rupture that are not critical concerns for the parent event. For example, the specific concerns for steam generator overfill include static loading of the steam line piping, water slug and water hammer loadings, and the possibility that safety related equipment, such as the safety valves and the turbine driven auxiliary feedwater pump(s) which interface with the main steam system, may be damaged or may fail to perform their intended functions under steam generator overfill conditions. These specific concerns are also applicable to a steam generator tube rupture since a

steam generator tube rupture can lead to steam generator overfill. Thus, on the basis of these specific concerns, steam generator overfill and steam generator tube rupture were considered important enough to warrant treatment as separate events.

These events of concern correspond to the first eight Selection Criteria (see Section 2.1). Therefore, by evaluating the system failure modes against each of these events, the first eight Selection Criteria are also being evaluated.

All of the systems defined in the H. B. Robinson Unit 2 FSAR were analyzed in this study. It was also decided to analyze safety grade systems as well as nonsafety grade systems in order to verify compliance with Appendix B of Standard Review Plan (SRP), Section 7.1[2] on Conformance to IEEE Standard 279. It was recognized that most safety grade systems are only single failure proof for a certain required action. For example, low pressure safety injection (LPSI) is single failure proof for failure to operate when required, such as during a loss of coolant accident. However, LPSI is not single failure proof for inadvertent operation at low reactor vessel pressures and inadvertent LPSI operation can contribute to an increase in reactor coolant system inventory.

The complete FMEA is documented in additional reports.[3,4,5] These reports were transmitted and reviewed, and with modifications based on comments received, the results of the FMEA (the selected systems) for each event of concern are shown in Table A-1.

These systems and applicable failure modes were then subjected to deterministic computer analyses (see Section 2.5 and Appendix C) in order to make a final determination as to whether the system failure mode will result in making the applicable transient or accident for the particular event of concern more severe than previously analyzed in the H. B. Robinson Unit 2 FSAR.

TABLE A-1. SELECTED SYSTEMS FOR EVENTS OF CONCERN

Event of Concern	Suspected System and Failure Modes
1. Reactor coolant overcool	A. Reactor coolant system and pumps--inadvertent start
	B. Pressurizer overpressure protection system--inadvertent opening
	C. Safety injection system--inadvertent start
	D. Residual heat removal system--inadvertent start
	E. Chemical and volume control system--high makeup flow and/or low letdown flow
	F. Reactor protection system--inadvertent reactor trip
	G. Control rod drive system--inadvertent insertion or dropped rod
	H. Feedwater and condensate system--high feed flowrate or feedwater heating fails
	I. Steamline overpressure protection system--inadvertent PORV or safety valve opening
	J. Main steam system--inadvertent MSIV opening
	K. Turbine generator system--inadvertent turbine control valve opening
	L. Auxiliary feedwater system--inadvertent start
	M. Steam generator--tube rupture
	N. Steam generator blowdown system--high flowrate
	O. Auxiliary steam system--high flowrate
	P. Main condenser, evacuation, and circulating water systems--increased vacuum or high circulating water flow
	Q. Steam dump system--inadvertent valve opening
	R. Component cooling water system--high flowrate
2. Increase in reactor pressure	A. Reactor coolant system and pumps--decreased flow
	B. High head safety injection system--inadvertent start
	C. Residual heat removal system--inadvertent start or low flow
	D. Chemical and volume control system--high makeup and/or low letdown flow
	E. Pressurizer pressure control system--controlling pressure high
	F. Accumulator tank system--inadvertent injection
	G. Control rod drive system--rod withdrawal or ejection
	H. Feedwater and condensate systems--no flow
	I. Main steam system--no steam flow
	J. Steam generator--fails to transfer heat
	K. Turbine generator systems--inadvertent control valve closure
	L. Auxiliary steam--no flow
	M. Main condenser, evacuation, and circulating water systems--loss of vacuum or no circulating water flow
	N. Steam dump system--fails to operate
3. Positive reactivity increase	A. Reactor coolant system and pumps--inadvertent start
	B. Chemical and volume control system--add nonborated water
	C. Control rod drive system--inadvertent withdrawal or ejection
	D. Feedwater and condensate systems--high flowrate and/or loss of heating

TABLE A-1. (continued)

Event of Concern	Suspected System and Failure Modes
3. Positive reactivity increase (continued)	E. Steamline overpressure protection system--inadvertent PORV or safety valve opening F. Main steam system--inadvertent MSIV opening G. Turbine generator system--inadvertent control valve opening H. Auxiliary feedwater system--inadvertent start I. Steam generator blowdown system--high flowrate J. Auxiliary steam system--increased flow K. Main condenser, evacuation, and circulating water systems--increased vacuum or circulating water flow L. Steam dump system--inadvertent valve opening
4. Increase in reactor coolant system inventory	A. High head safety injection system--inadvertent start B. Residual heat removal system--inadvertent start C. Chemical and volume control system--high makeup and/or reduced letdown flow D. Accumulator tank system--inadvertent injection
5. Decrease in RCS flow	A. Reactor coolant system and pumps--no flow B. Residual heat removal system--no flow
6. Decrease in RCS inventory	A. Reactor coolant system and pumps--no flow which increases pressure B. Pressurizer overpressure protection system--inadvertent PORV or safety valve opening C. Residual heat removal system--no flow D. Chemical and volume control system--no charging flow or high letdown flow E. Pressurizer pressure control system--pressure controlled high F. Control rod drive system--rod ejection G. Main steam system--inadvertent MSIV closure H. Turbine generator system--inadvertent control valve closure I. Steam dump system--inadvertent valve closure J. Steam generator--tube rupture K. Main condenser, evacuation, and circulating water systems--loss of vacuum or no circulating water flow
7. Steam generator overfill	A. Control rod drive system--withdrawal or ejection of rods B. Feedwater and condensate system--high flowrate C. Steam line overpressure protection system--inadvertent opening of a PORV or safety valve D. Main steam system--high flowrate or inadvertent MSIV opening E. Turbine generator system--inadvertent valve opening F. Auxiliary feedwater system--inadvertent start G. Steam generator--tube rupture H. Steam generator blowdown--low flowrate I. Auxiliary steam system--high flowrate J. Main condenser, evacuation, and circulating water systems--increased vacuum or high circulating water flow K. Steam dump system--inadvertent opening or high flowrate

TABLE A-1. (continued)

Event of Concern	Suspected System and Failure Modes
8. Steam generator tube rupture	A. Reactor coolant system and pumps--no flow
	B. Chemical and volume control system--high charging flow and no letdown flow
	C. Pressurizer pressure control system--pressure being controlled high
	D. Control rod drive system--uncontrolled rod withdrawal
	E. Feedwater and condensate system--no flow or high flow to the affected steam generator
	F. Steamline overpressure protection system--inadvertent PORV or safety valve operation
	G. Main steam system--inadvertent opening or failure to close an MSIV on the affected SG, and inadvertent closure of an MSIV on a nonaffected steam generator
	H. Turbine generator systems--inadvertent control valve closure
	I. Auxiliary feedwater system--inadvertent start
	J. Steam generator--tube rupture
	K. Steam generator blowdown system--high flow
	L. Steam generator sampling system--high flow
	M. Auxiliary steam system--no flow
	N. Main condenser, evacuation, and circulating water systems--loss of vacuum or no circulating water flow
	O. Steam dump system--fails to operate

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APPENDIX B

DETAILED H. B. ROBINSON UNIT 2 COMPUTER MODEL DESCRIPTION

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FIGURES

EFFECTS OF CONTROL SYSTEM FAILURES ON TRANSIENTS AND ACCIDENTS AT A 3-LOOP WESTINGHOUSE PRESSURIZED WATER REACTOR

APPENDIX B

DETAILED H. B. ROBINSON UNIT 2 COMPUTER MODEL DESCRIPTION

B.1 Thermal-Hydraulic Modeling

This section describes the H. B. Robinson (HBR) pressurized water reactor (PWR) RELAP5 model.[1] HBR is a 3-loop Westinghouse plant located in South Carolina and operated by Carolina Power and Light Company. A description of the HBR thermal-hydraulic model is presented first, followed by brief descriptions of the control system models and the modeling of the various plant trips.

Figure B-1 shows the HBR reactor vessel model nodalization. The reactor vessel model consists of 22 thermal-hydraulic volumes, 33 junctions, and 56 heat structures. Core power was modeled using RELAP5-generated data regarding power response to changing moderator and fuel temperatures, and control rod positioning. Core decay heat was assumed to be at the American Nuclear Society (ANS) standard rate where applicable.[2] The reactor vessel model represents the downcomer, downcomer bypass, lower plenum, core, upper plenum, and upper head. Leakage paths from the downcomer to the upper head, downcomer to downcomer bypass, downcomer bypass to the lower plenum, cold leg inlet annulus to upper plenum, and upper plenum to upper head via the guide tubes are represented. Heat structures representing the core fuel and the external and internal metal masses of the vessel are modeled and are represented in Figure B-1 by the shaded regions adjacent to the various volumes.

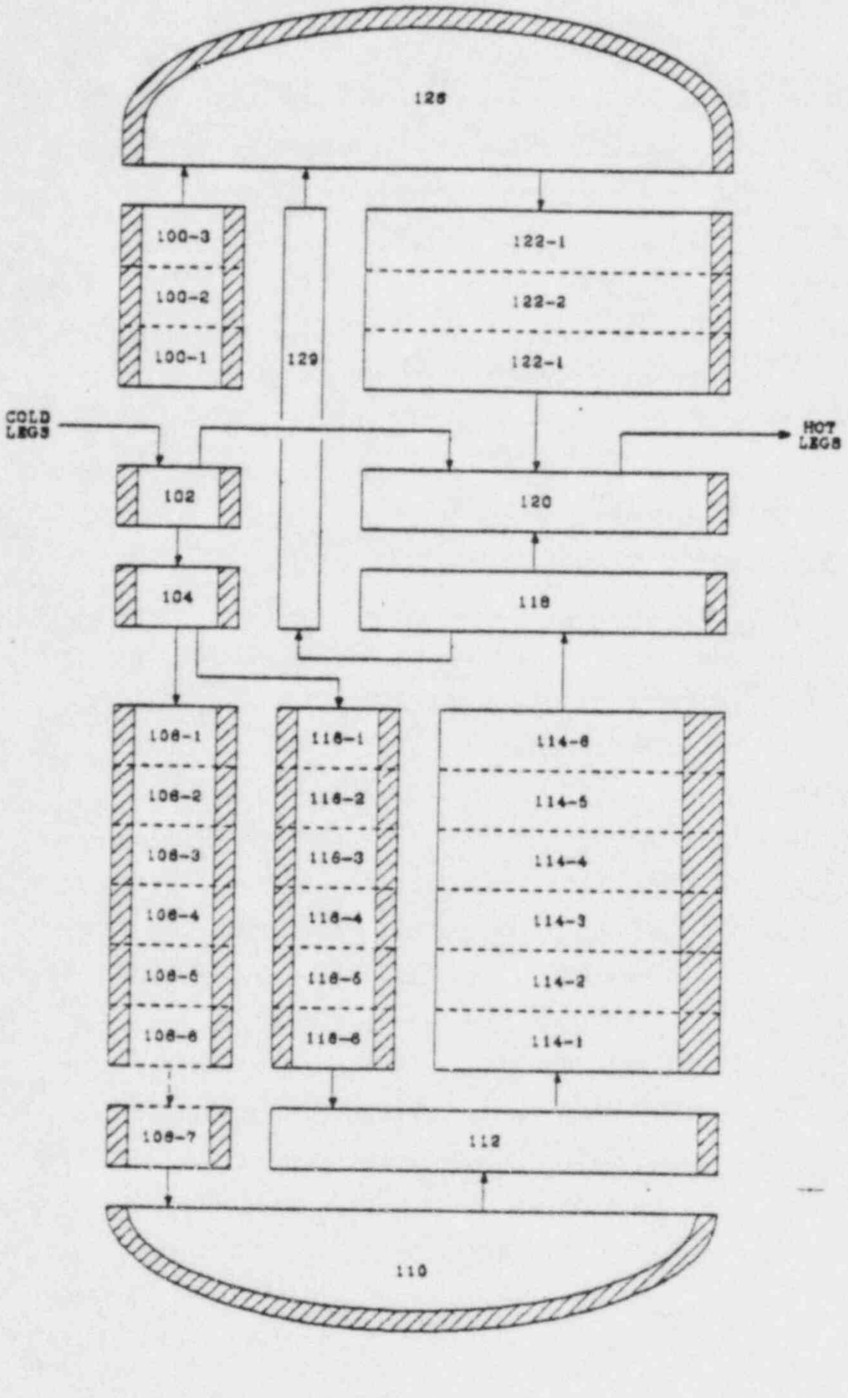


Figure B-1. Reactor vessel nodalization.

Nodalization diagrams of the three reactor coolant system (RCS) loops, the steam generators, steam generator feedwater lines, steam lines, and associated heat structures (represented by the shaded regions) are shown in Figures B-2 through B-4. Each reactor coolant system loop consists of a hot leg, steam generator inlet plenum, steam generator tube bundle, steam generator outlet plenum, reactor coolant pump (RCP) suction leg, RCP, and RCP discharge leg. Additionally, the high pressure injection (HPI) ports, accumulators, low pressure injection (LPI) ports, and the chemical and volume control system (CVCS) have been modeled as boundary conditions. Each reactor coolant system loop consists of 26 volumes, 26 junctions, and 22 heat structures. Additionally, the CVCS is represented with a volume and junction connected to the Loop B RCP discharge volume.

The pressurizer is connected to RCS Loop C via the surge line and one of the spray lines; and is connected to RCS Loop B via the other spray line. The two pressurizer power operated relief valves (PORVs) have been modeled as a single valve with the capacity of both PORVs. The pressurizer safety valves were represented in a similar manner. The pressurizer on-off heaters and proportional heaters were also modeled. The pressurizer and associated piping were modeled with 16 volumes, 18 junctions, and 16 heat structures.

The steam generator primary side consists of inlet and outlet plena, modeled with a single volume each, and 8 volumes representing the tube bundle. Eleven heat structures representing the inlet and outlet plena, the tube sheet, and the tube bundle were also modeled.

The RCP suction legs were modeled with the correct elevation changes, so that the inlet and outlet were at the same elevation. The apparent inlet-to-outlet elevation difference indicated in the nodalization diagrams was done to show both the cold leg section and the hot leg section in the same figure. The RCP suction leg consists of 4 volumes, 3 junctions, and 4 heat structures (representing the piping metal mass).

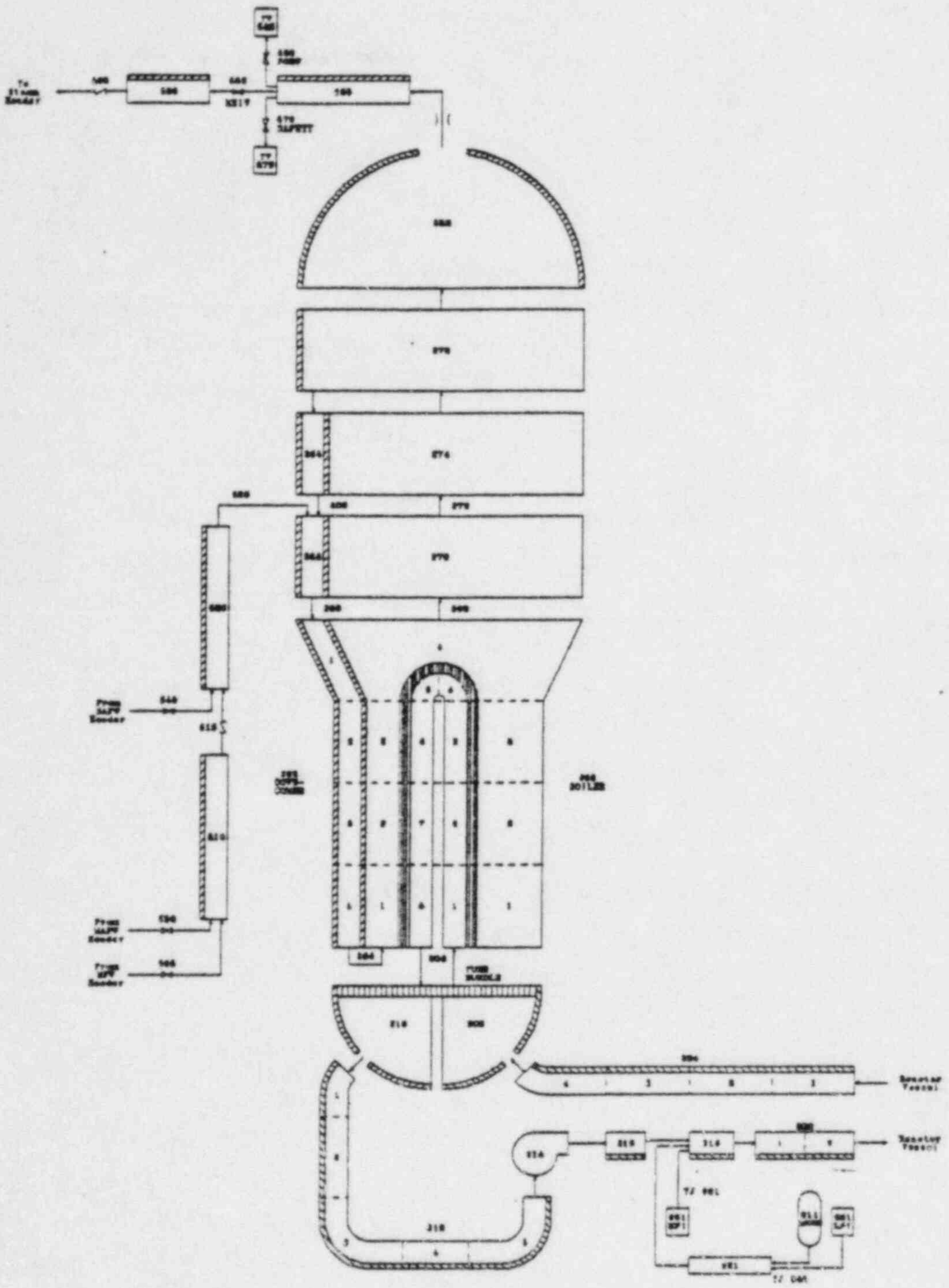


Figure B-2. Primary Loop A nodalization.

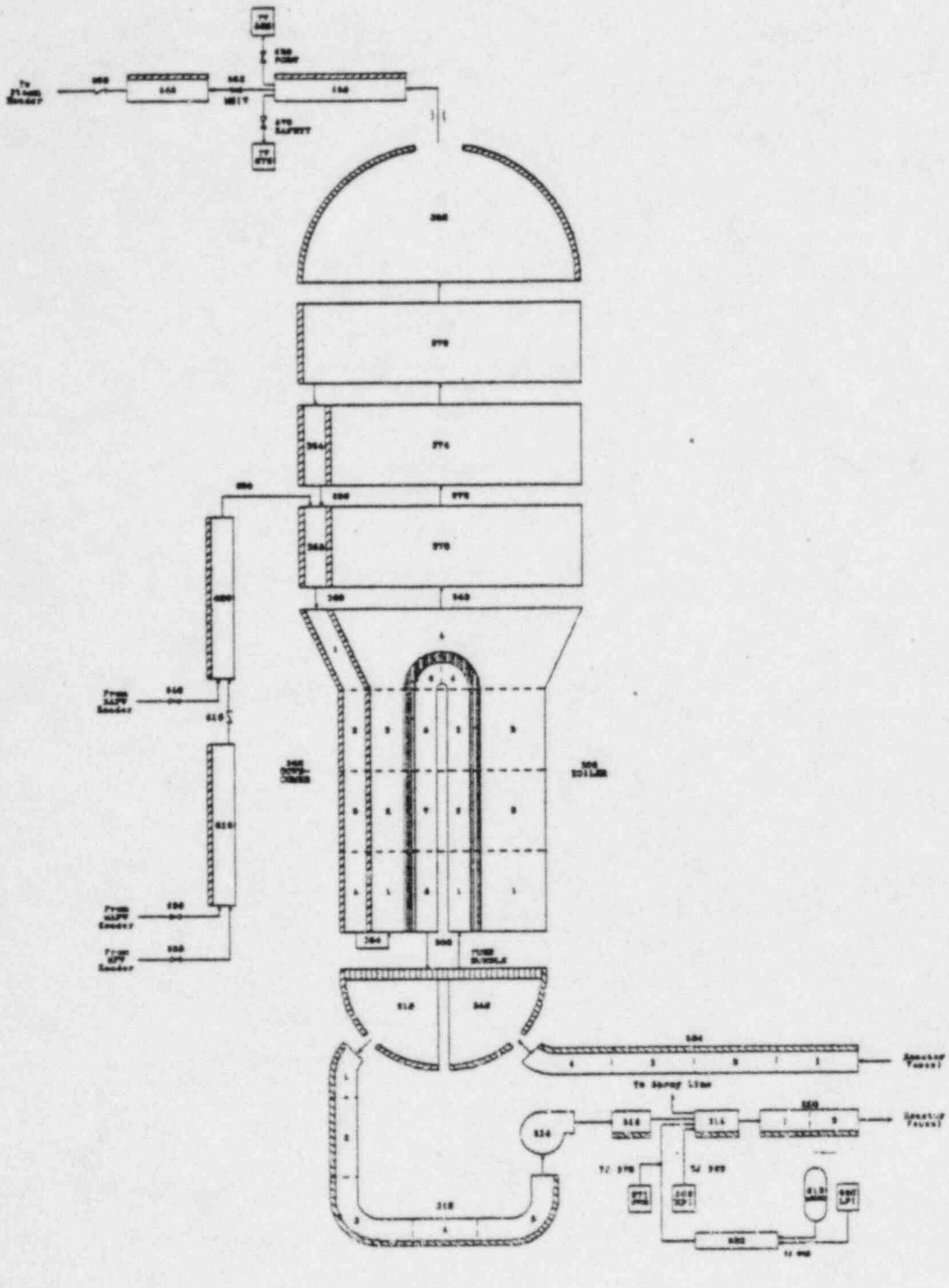


Figure B-3. Primary Loop B nodalization.

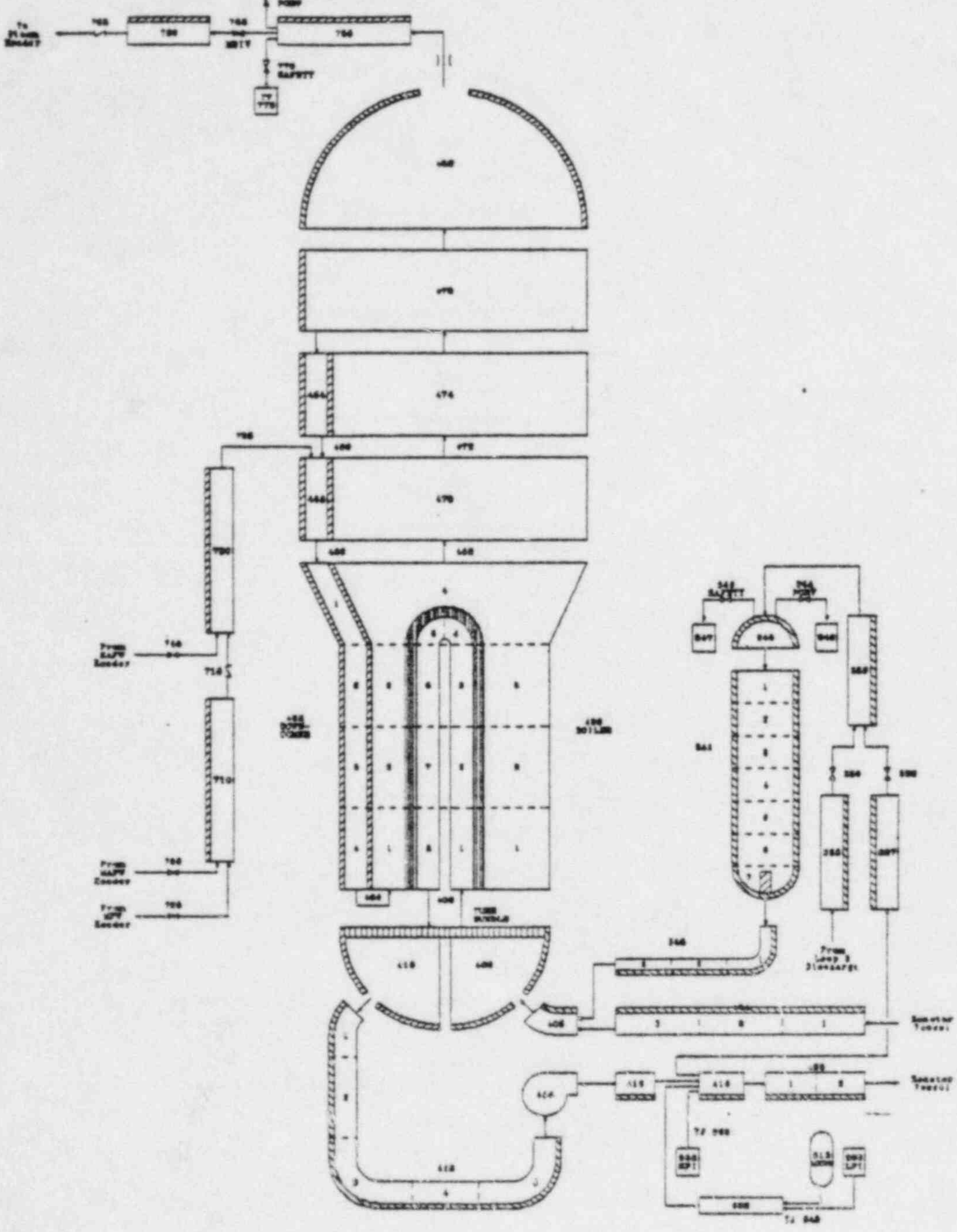


Figure B-4. Primary Loop C nodalization.

The RCPs were modeled using the RELAP5 pump component. The pump component consists of 1 volume and 2 associated junctions. The pump head, torque, and angular velocity are computed from volume-oriented quantities. The head developed by the pump is divided equally between the suction and discharge junctions, and is treated like a body force in the momentum equations for each junction. The interaction between the pump and fluid is described by empirically developed curves relating the head and torque response of the pump to the volumetric flow and pump angular velocity. The pump four-quadrant curves were converted to pump homologous curves, which were subsequently used in the input data.

The RCP discharge legs were modeled using 3 volumes, 3 junctions, and 3 heat structures. The low pressure injection, high pressure injection, and accumulator junctions were connected to this section of piping, as shown in Figures B-2 through B-4. Additionally, the pressurizer spray lines were connected to Loops B and C in this section of the RCS loop piping.

The accumulators were modeled using the RELAP5 accumulator component. The accumulator component consists of a single volume and a single junction. The component contains an internal valve that opens when static pressure drops, and closes when reverse flow conditions exist. The surge line volume is combined with the liquid volume; however, the momentum equation is formulated to include inertial and wall friction effects in the line. There are two special features of this component. First, the model contains its own heat transfer package; and second, once all the liquid is expelled from the accumulator, this component converts to a normal volume filled with nitrogen. The heat transfer model uses standard correlations for natural convection for vertical flat plates (tank wall) and horizontal flat plates (water surface and tank top). In addition, there is a provision to model the evaporation of the liquid, and then to model the heat given up by the vapor as it condenses. Modeling this effect helps give the polytypic response typical of accumulators.

The CVCS was modeled as a boundary condition which is controlled by the appropriate control system quantities. Time delays associated with CVCS pump speed response were not modeled because they were not considered significant relative to the response times expected in the proposed transient scenarios.

The HPI and LPI were also modeled as boundary conditions. The flow rates were modeled as functions of the RCP discharge leg pressure, and were based on data (provided by the utility) regarding system performance.

Figures B-2 through B-4 are nodalization diagrams of the steam generator secondary systems. The steam generator models are the same for each steam generator and consist of a downcomer, boiler region, separator region, and steam dome. Recirculation flow from the steam separator to the upper portion of the downcomer has been modeled. There are 14 volumes, 15 junctions, and 22 heat structures (including the tube bundle) associated with each steam generator.

The steam generator separators were modeled using the RELAP5 separator component. The separator component is a nonmechanistic model consisting of a volume and three junctions (mixture inlet, steam outlet, and recirculation). A steam-water inflowing mixture is separated by defining the quality of the outflow streams using empirical functions. No attempt is made to model the actual separation process from first principles.

The feedwater lines from the main feedwater header to the associated steam generator are shown in Figures B-2 through B-4. The motor-driven auxiliary feedwater (MAFW) and steam-driven auxiliary feedwater (SAFW) isolation valves are also shown. The feedwater lines are modeled using 2 volumes, 2 junctions, and 2 heat structures. A check valve between the first and second feedwater line volumes has been modeled as one of the two junctions.

The steam lines from the steam generator steam dome to the steam header are also shown in Figures B-2 through B-4. Included in the nodalization of the steam lines are the steam line PORV and the steam line safety valves. The five HBR safety valves per steam line were modeled as a single valve per steam generator. Hysteresis was included in the modeling of safety valve operation. The main steam isolation valves (MSIVs) and their associated downstream check valves were also modeled. The steam line models consist of 4 volumes, 4 valve junctions, and 2 heat structures (representing the steam line metal mass). The PORV and safety valves discharge to a constant-pressure volume representing the atmosphere.

Figure B-5 shows the steam header and feedwater piping system nodalization diagrams. The steam header model consists of the steam header, the steam line from the steam header to the turbine, a model of the turbine governor and stop valves, the turbine, the steam dump valves, and the condenser. The condenser was modeled as a boundary condition downstream of the turbine and the steam dump valves. The turbine was modeled as a single volume with a large loss coefficient between the turbine and the condenser. The approximation yielded reasonably good results for a range of flow and pressure conditions. The five HBR steam dump valves were modeled as a single valve, with control logic to simulate the appropriate valve response to varying steam dump demands.

The feedwater piping system consists of: the condenser (modeled as a boundary condition); a condensate pump, representing the three HBR condensate pumps; a train of five low-pressure feedwater heaters representing the two HBR trains, the low pressure feedwater heater bypass valve, representing the HBR bypass system; a heater drain pump boundary condition; two main feedwater pumps with downstream check valves; a train of two high-pressure feedwater heaters, representing the two HBR trains of heaters; and the feedwater control valves.

The condensate pump and the two feedwater pumps were modeled using the RELAP5 pump component. These pumps are constant-speed pumps, therefore, no modeling of the pump motors was required. The feedwater heater heat

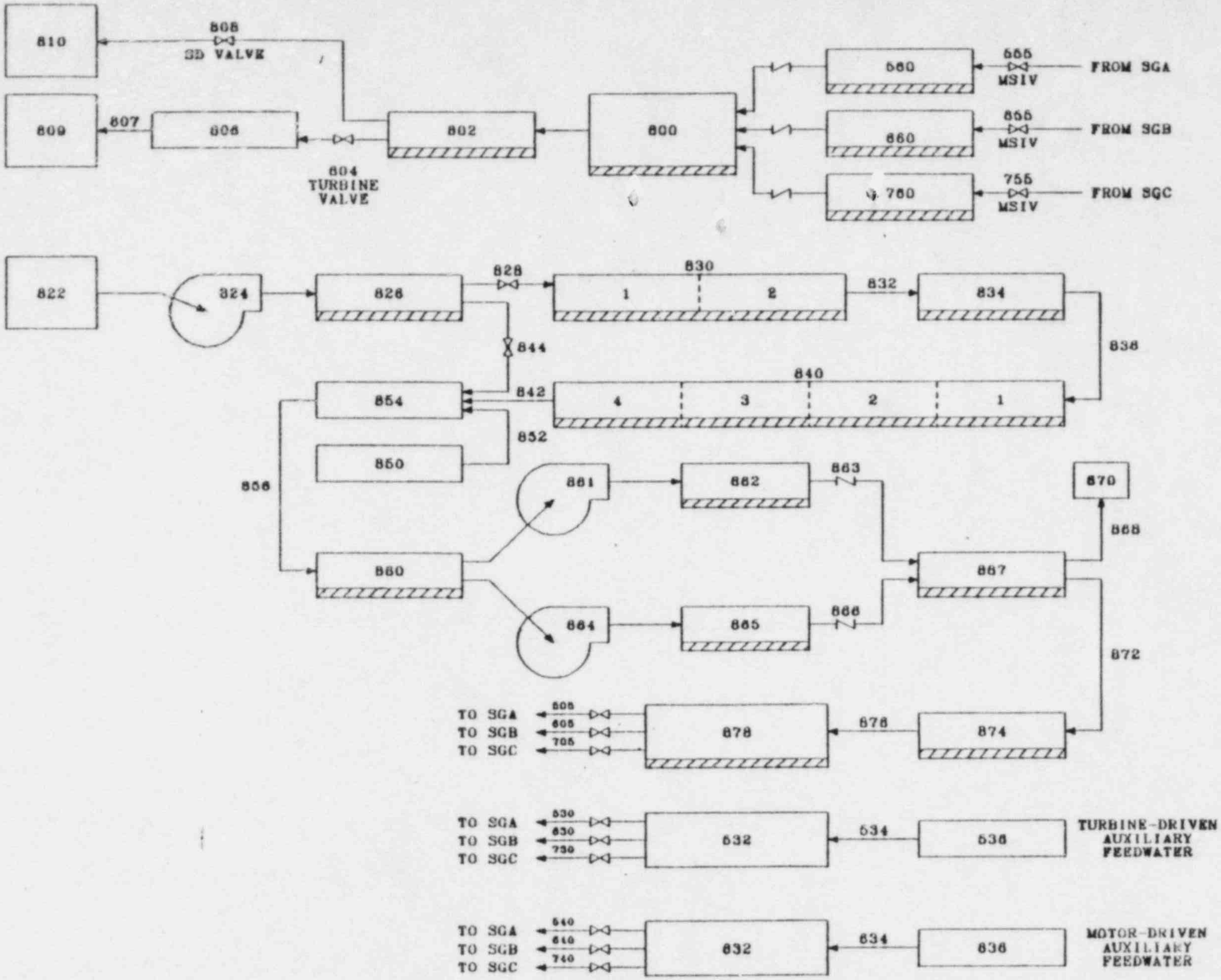


Figure B-5. Stea.a header and feedwater systems.

sources were modeled using control variables as opposed to modeling them as heat exchangers. This substantially reduced the number of components required to represent the feedwater train. The feedwater valves were modeled in such a manner that the valves can be used to represent either the main feedwater control valves or the main feedwater bypass valves.

The motor-driven and turbine-driven auxiliary feedwater train models are also represented in Figure B-5. These systems were modeled as boundary conditions, with a common header discharging to the three steam generators via the appropriate feed line header. The auxiliary feedwater pumps were not modeled due to the limited information available regarding their performance capabilities, and due to the size of the HBR RELAP5 model.

B.2 Control System Modeling

A description of the HBR RELAP5 control system models is presented in this section. The control systems were modeled using information obtained from proprietary documents; therefore, to ensure that no proprietary information is included, only a general discussion of the function of each system is provided in this document. The control systems were modeled as functionally accurate as possible and are good representations of the actual systems.

The steam dump control system is described in Section B.2.1, followed by descriptions of the steam generator level control system in Section B.2.2, the pressurizer pressure control system in Section B.2.3, the pressurizer level control system in Section B.2.4, and the rod control system in Section B.2.5.

B.2.1 Steam Dump Control System

The steam dump control system (SDCS) is described in this section. A block diagram of the SDCS is shown in Figure B-6. The SDCS consists of four distinct, but interrelated systems, which are indicated by the dashed boxes in Figure B-6.

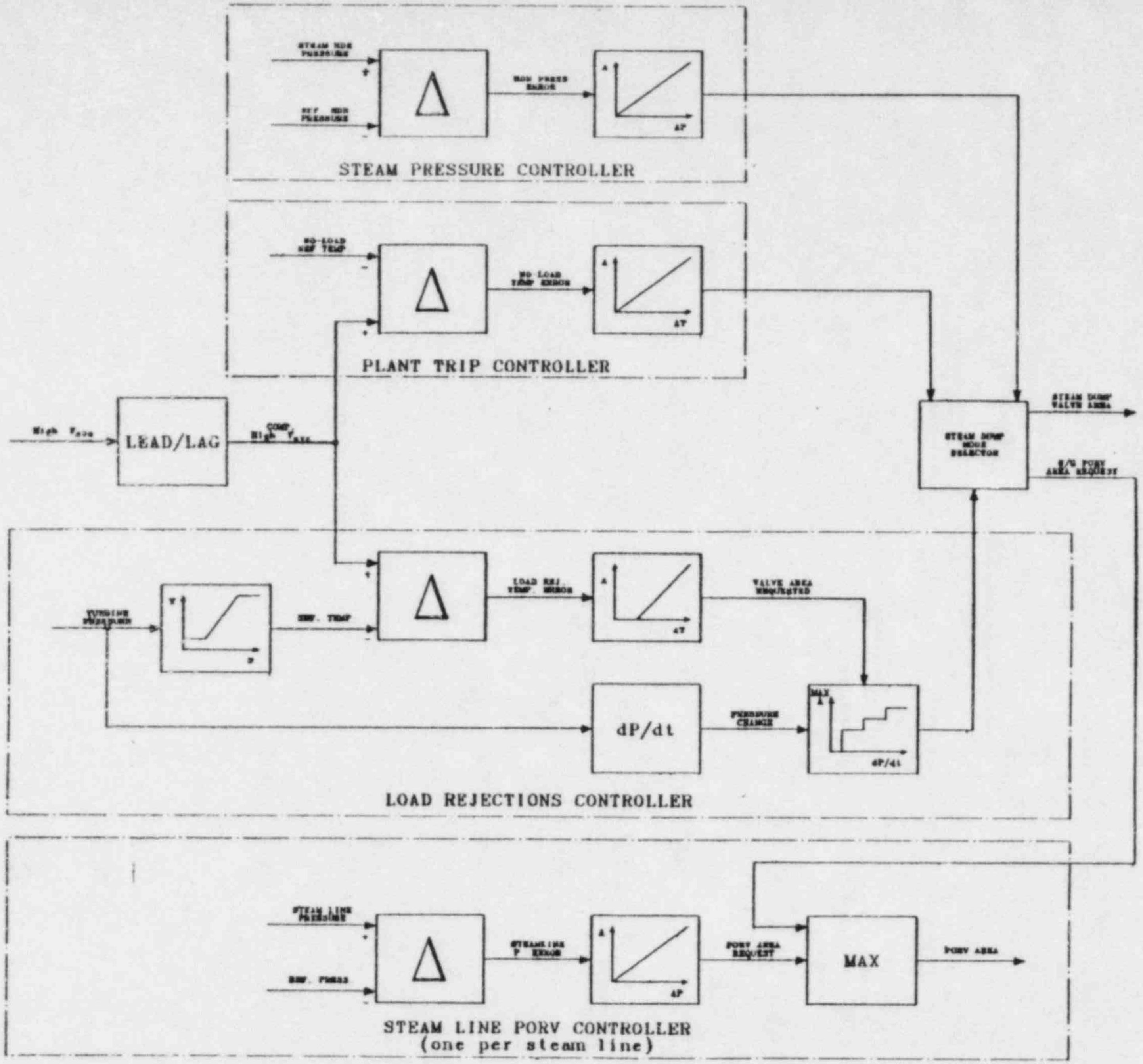


Figure B-6. Steam dump control system.

The purposes of the SDCS are to:

1. Permit the nuclear plant to accept sudden losses of load without tripping the reactor,

2. Remove stored energy and residual heat following a plant trip and bring the plant to equilibrium no-load conditions without actuation of the steam generator safety valves,

3. Permit control of the steam generator pressure and permit a manually controlled cooldown of the plant.

The first requirement above is accomplished using the load rejection controller, and, when the loss of load is sufficiently high, the steam line PORV controller. The second requirement is met using the plant trip controller. The steam pressure controller is used to maintain steam line pressure at the desired setpoint during periods of no-load operation. The steam line PORVs are used to prevent overpressurization of the steam lines during all periods of operation, and to assist in cases of large load rejections.

B.2.2 Steam Generator Level Control System

The steam generator level control system (SGLCS) is described in this section. A schematic diagram of the SGLCS is shown in Figure B-7. The block diagram is a summary of the functional form of the SGLCS and does not include all of the SGLCS control system components.

The SGLCS is a three element control system designed to maintain the correct amount of mass in the steam generator secondaries. The input signals to this system are: the reference level derived from the implied plant load (as determined from the turbine first stage pressure); the steam generator level obtained from the appropriate level transducer; the steam flow rate; and the feedwater flow rate. A level error between the

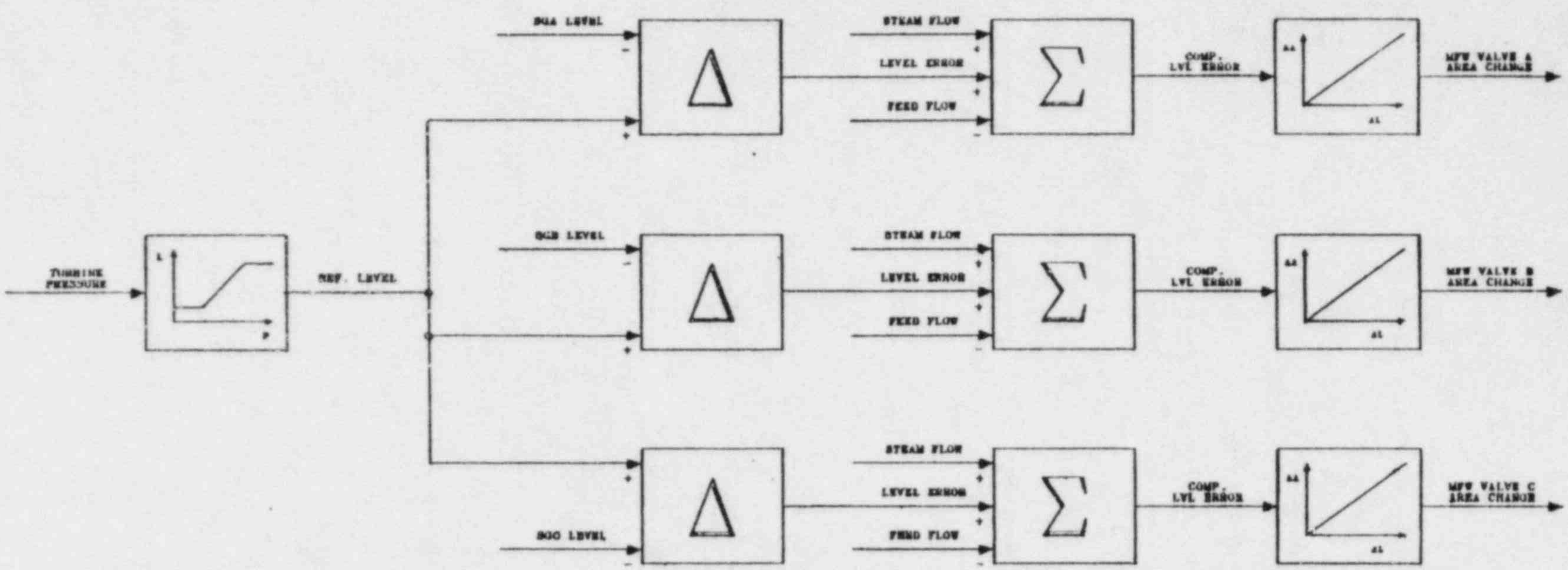


Figure B-7. Steam generator level control system.

reference level and the indicated level is used in conjunction with the difference between the steam flow rate and the feedwater flow rate to generate a feedwater valve area change.

B.2.3 Pressurizer Pressure Control System

The pressurizer pressure control system (PPCS) is described in this section. A functional block diagram of the PPCS is shown in Figure B-8. The purpose of the PPCS is to maintain the desired primary system pressure. This function is performed using spray valves, power operated relief valves (PORVs), proportional heaters, and on-off heaters.

The pressurizer pressure is compared with the reference setpoint to determine the pressure error. This error signal is compensated and then used to control the function of the spray valves, one of the two PORVs, and the proportional and on-off heater sources. The other PORV area is controlled using the uncompensated pressurizer pressure signal.

The PPCS model includes all the trips and setpoints used in the HBR plant, with two exceptions. First, the spray valves do not maintain a minimum flow rate, as they do in the plant, because of difficulties incurred due to thermal-hydraulic considerations. The minimum flow requirement is used in the plant to maintain the spray line temperature at the cold leg temperature in order to prevent thermal stress when the valves are required to open. To compensate, the modeled spray lines were initialized at the cold leg temperature, and no heat losses to the containment were considered (the lines were perfectly insulated). The second modeling exception is in the amount of power supplied to the proportional heaters during steady state operation. The heaters normally operate at 2000 kW to make up for plant heat losses and pressure decay due to the spray line minimum continuous flow requirement. Since the pressurizer tank walls were modeled as perfectly insulated heat structures, and there was no spray flow during steady state, this 2000 kW heater source was subtracted from the total possible proportional heater source of 4000 kW.

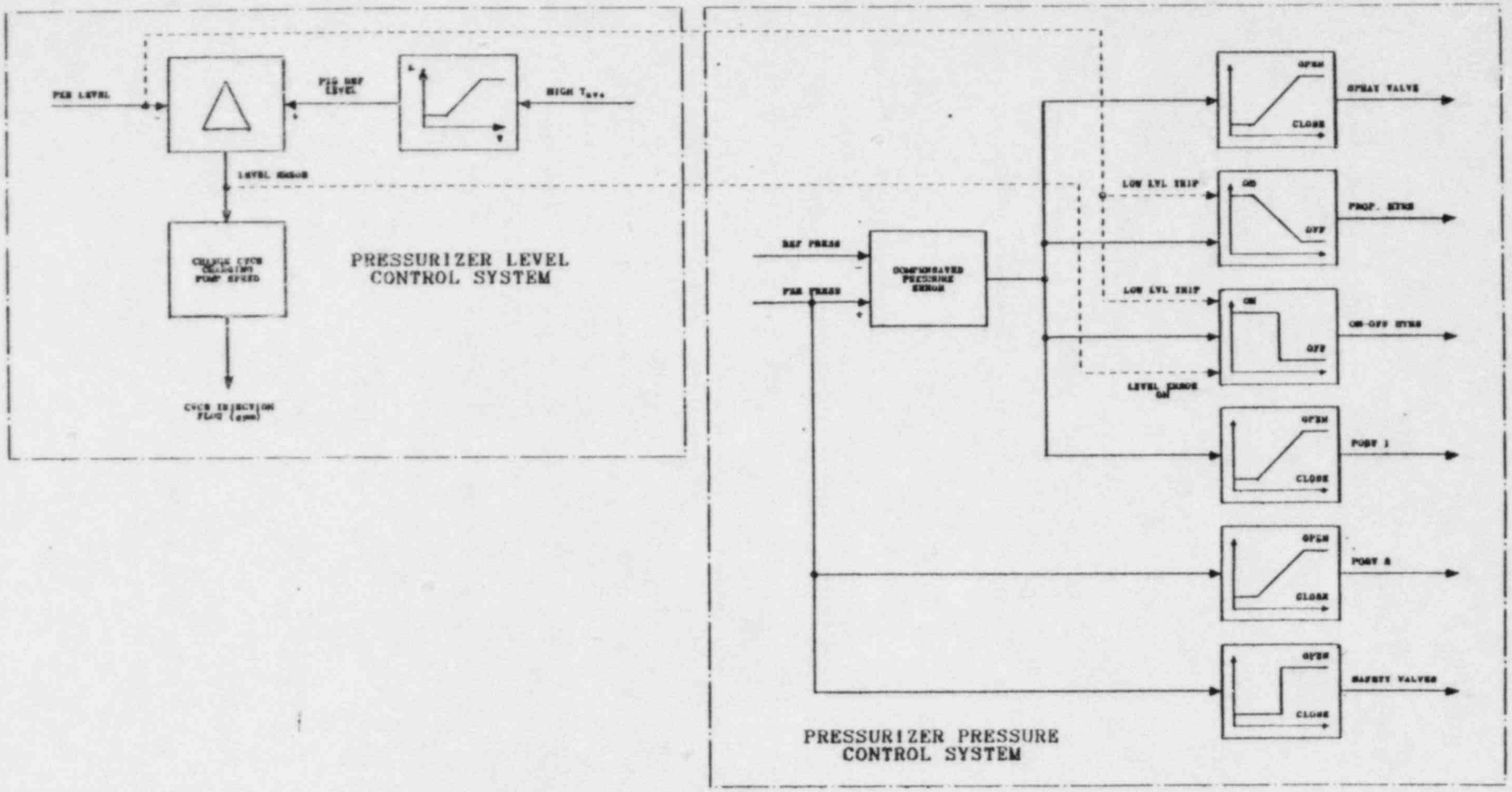


Figure B-8. Pressurizer control systems.

B.2.4 Pressurizer Level Control System

The pressurizer level control system (PLCS) is described in this section. A functional block diagram of the PLCS is shown in Figure B-8. The purpose of the PLCS is to maintain the desired amount of liquid inventory in the primary coolant system. The amount of water inventory in the primary system may be inferred from the liquid level in the pressurizer, which varies as a function of the primary system average coolant temperature.

The pressurizer level setpoint is specified as a function of the reactor coolant system average temperature. The level setpoint is subtracted from the actual level which has been determined from a set of differential pressure taps located in the pressurizer. The pressurizer level error signal is used as the input signal in a P-I controller. The output of the controller specifies the amount of change in the CVCS charging pump speed to bring about the desired change in the primary system coolant inventory.

The level error is also used to actuate the on-off heaters when the pressurizer level error exceeds the setpoint level by 5%. Pressurizer heater demand is blocked when the pressurizer level is less than the low-level limit of 14%.

The PLCS is modeled to include the RCP seal injection contribution in addition to the charging flow demanded by the compensated pressurizer level error signal. The RCP seal injection flow is quantitatively correct, however, it is added to only one RCS loop.

B.2.5 Rod Speed Control System

The rod control system is described in this section. A block diagram of the rod control system is shown in Figure B-9. The purpose of this system is to regulate the reactor power based upon the plant load and the RCS average temperature.

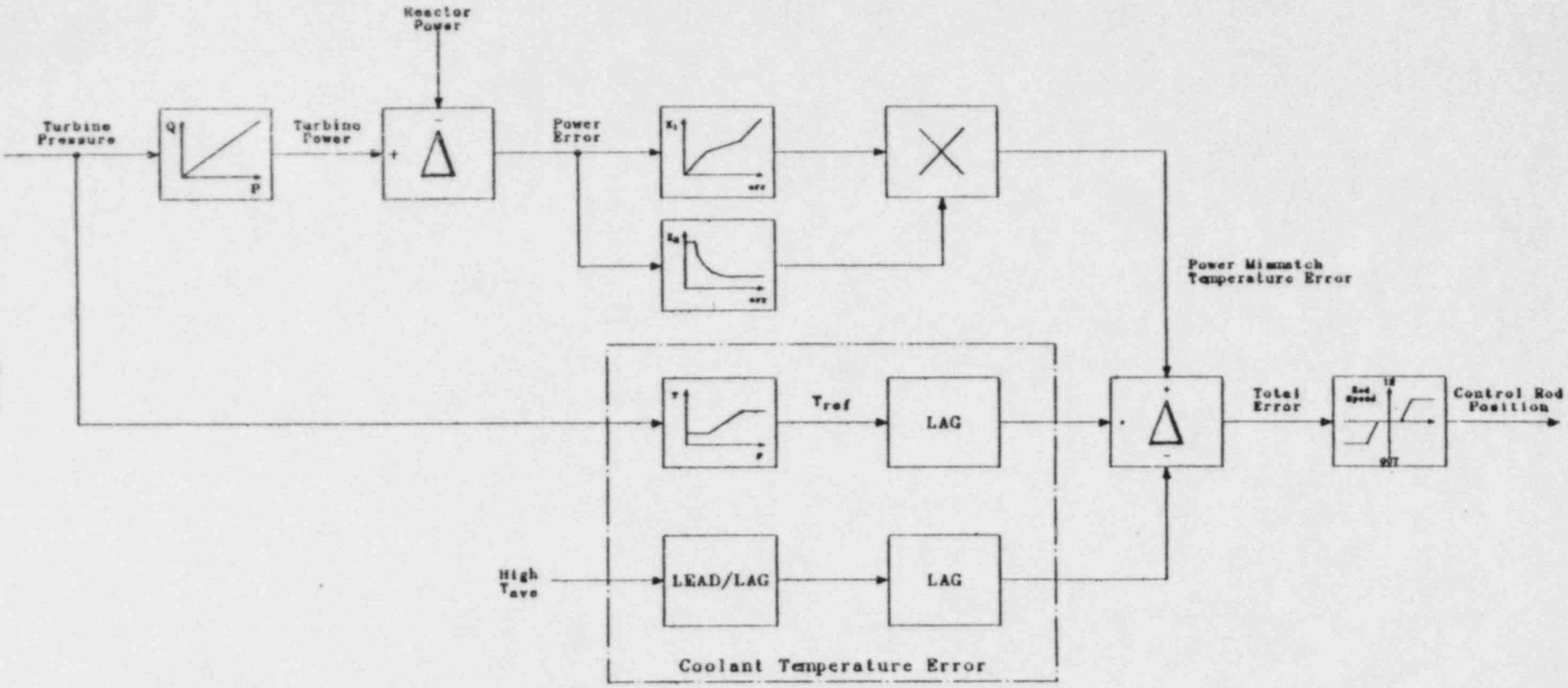


Figure B-9. Rod speed control system.

The plant load is inferred from the turbine first stage pressure. The difference between the plant load and the reactor power in conjunction with the difference between the RCS average temperature setpoint and the auctioneered average temperature is used to change the position of the reactor control rod banks. Movement of the control rods changes the reactor power. The rate of control rod movement is determined by the magnitude of the error signal.

Reactor power is calculated using the results of the RELAP5 point kinetics package to determine power contributions due to core temperature changes, and the results obtained from plant startup data regarding control rod bank worth. This approach has yielded satisfactory results in the calculations addressed by this report.

B.2.6 Additional Control Systems

Included in the control system package are miscellaneous controllers and trips that are modeled to represent various system functions that cannot be classified in any of the aforementioned systems. These controllers perform functions such as: (a) feedwater recirculation to the condenser during periods of low feedwater demand, (b) low pressure feedwater heater bypass due to low main feedwater pump suction pressure, (c) specification of the turbine governor valve area to regulate the turbine first stage pressure, and (d) control of the auxiliary feedwater system.

B.2.7 Trip Logic

The trips associated with various plant systems are indicated in Figure B-10. The setpoints for these trips were obtained from the Plant Limitations and Setpoints (PLS) document,[3] and other related sources of information. The primary functions of the trips are segregated by the boxes, with connecting arrows indicating the various trip interrelationships.

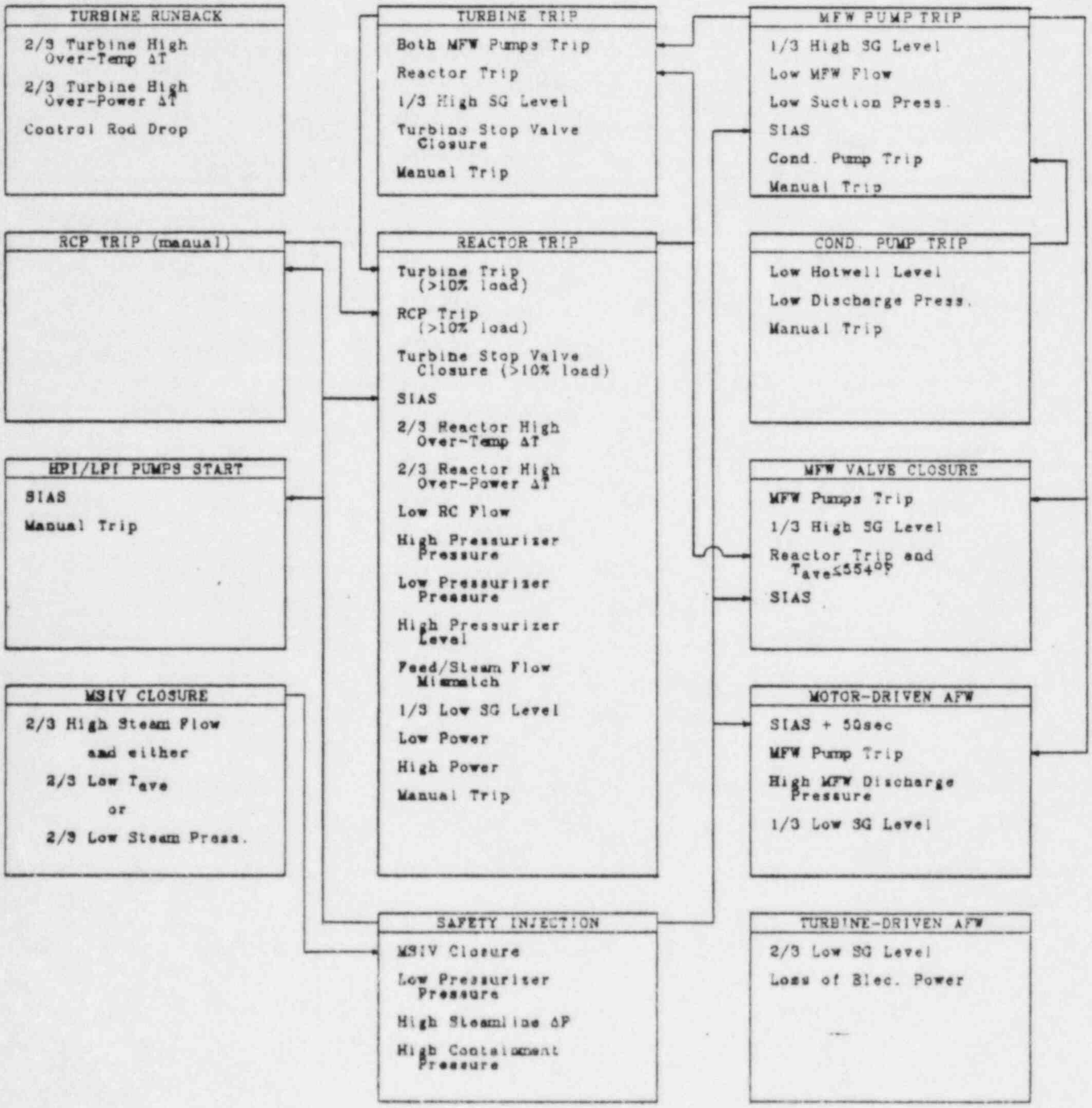


Figure B-10. H. B. Robinson Model trip logic.

B.3 Plant Model Initial Conditions

The RELAP5 model described above was initialized for various steady state conditions, as required by the prescribed scenarios. The calculated steady state conditions were compared with actual (or inferred) plant data, changes were then made where necessary to approximate, as closely as reasonably possible, the actual conditions. The steady state initialization data for the at-power cases are presented in Tables B-1 through B-4.

B.4 References

1. V. H. Ransom et al., RELAP5/MOD1 Code Manual Volume 1: System Models and Numerical Methods, NUREG/CR-1826 (EGG-2070 Draft, Revision 2), September 1981.

2. "Decay Heat Power in Light Water Reactors," American Nuclear Society, ANSI/ANS-5.1-1979, Lagrange Park, Illinois, August 1979.

3. H. B. Robinson Steam Electric Plant Unit No. 2 Precautions, Limitations, and Setpoints PLS-1, Reactor Control and Protection System, Proprietary, Revision 20, May 1981.

TABLE B-1. HBR 5% FULL POWER

STEADY STATE CONDITIONS

Parameter	RELAP5	Desired
Core power, MW	115	115
Pressurizer pressure, MPa (psia)	15.5 (2250)	15.5 (2250)
Hot leg temperature, K (°F)	562.9 (553.6)	560.9 (550.0)
Cold leg temperature, K (°F)	561.3 (550.6)	559.3 (547.0)
Pressurizer level, %	25	22
Reactor coolant flow, Kg/s (lbm/s)	12738 (28081.6)	12726 (28056)
Reactor coolant pump speed, RPM	1225.6	1190
Net makeup flow, gpm	35.8	0
Steam header pressure, MPa (psia)	7.04 (1021.3)	7.03 (1020.0)
Steam generator level, %	39.8	39.0
Steam generator mass (each), Kg (lbm)	59285 (130700)	58967 (130000)
Steam flow (each), Kg/s (lbm/s)	13.8 (30.35)	14 (31) (est.)
Feedwater flow (each), Kg/s (lbm/s)	17.4 (38.36)	14 (31) (est.)
Feedwater temperature, K (°F)	305.2 (89.7)	294.3 (70.0)

TABLE B-2. HBR 67% FULL POWER

STEADY STATE CONDITIONS

Parameter	RELAP5	Desired[a]
Core power, MW	1535.78	1541.0
Pressurizer pressure, MPa (psia)	15.4 (2230)	15.5 (2250)
Hot leg temperature, K (°F)	580.9 (586.0)	580.5 (585.3)
Cold leg temperature, K (°F)	558.9 (546.3)	558.9 (546.3)
Pressurizer level, %	43	44
Reactor coolant flow, Kg/s (lbm/s)	12860 (28351.0)	12726 (28056)
Reactor coolant pump speed, RPM	1237.8	1190
Net makeup flow, gpm	21.5	0
Steam header pressure, MPa (psia)	5.81 (842.0)	5.74 (832.4)
Steam generator level, %	52.3	52.0
Steam generator mass (each), Kg (lbm)	48172 (106200)	Unknown
Steam flow (each), Kg/s (lbm/s)	273 (601)	284 (626)
Feedwater flow (each), Kg/s (lbm/s)	265 (585)	284 (626)
Feedwater temperature, K (°F)	480 (404)	480 (404)

a. Estimated based on plant startup data.

TABLE B-3. HBR 100% FULL POWER

STEADY STATE CONDITIONS

Parameter	RELAP5	Desired
Core power, MW	2300	2300
Pressurizer pressure, MPa (psia)	15.5 (2250)	15.5 (2250)
Hot leg temperature, K (°F)	591.4 (604.8)	591.4 (604.5)
Cold leg temperature, K (°F)	558.9 (546.3)	558.9 (546.3)
Pressurizer level, %	54.5	53.3
Reactor coolant flow, Kg/s (lbm/s)	12726 (28055.5)	12726 (28056)
Reactor coolant pump speed, RPM	1247.1	1190
Net makeup flow, gpm	0	0
Steam header pressure, MPa (psia)	5.50 (804.0)	5.70 (828.0)
Steam generator level, %	53.7	52.0
Steam generator mass (each), Kg (lbm)	44253 (97560)	42302 (93260)
Steam flow (each), Kg/s (lbm/s)	425 (937)	424.2 (935.2)
Feedwater flow (each), Kg/s (lbm/s)	424 (935)	424.2 (935.2)
Feedwater temperature, K (°F)	500 (441)	501 (442)

TABLE B-4. HBR 102% FULL POWER

STEADY STATE CONDITIONS

Parameter	RELAP5	Desired[a]
Core power, MW	2346	2346
Pressurizer pressure, MPa (psia)	15.7 (2280)	15.7 (2280)
Hot leg temperature, K (°F)	592.3 (606.4)	592.1 (606.0)
Cold leg temperature, K (°F)	561.3 (550.6)	561.0 (550.2)
Pressurizer level, %	54.6	53.3
Reactor coolant flow, Kg/s (lbm/s)	13138 (28964)	Unknown
Reactor coolant pump speed, RPM	1241.5	1190
Net makeup flow, gpm	-12.0	0
Steam header pressure, MPa (psia)	5.22 (756.8)	Unknown
Steam generator level, %	51.8	52.0
Steam generator mass (each), Kg (lbm)	43807 (96577)	Unknown
Steam flow (each), Kg/s (lbm/s)	428 (943)	433 (954)
Feedwater flow (each), Kg/s (lbm/s)	430 (949)	433 (954)
Feedwater temperature, K (°F)	494 (430)	494 (430)

a. Estimated from plant startup data.

APPENDIX C
SCENARIO COMPUTER ANALYSIS AND EFFECTS

CONTENTS

TABLES

EFFECTS OF CONTROL SYSTEM FAILURES ON TRANSIENTS AND ACCIDENTS AT A 3-LOOP WESTINGHOUSE PRESSURIZED WATER REACTOR

APPENDIX C--SCENARIO COMPUTER ANALYSIS AND EFFECTS

The purpose of the event scenario development process and the computer analysis is to develop postulated scenarios in a logical manner and deterministically examine these postulated scenarios using the computer code described in Appendix B to determine if these postulated scenarios result in transients or accidents that are more severe than previously analyzed in Chapter 15 of the H. B. Robinson Steam Electric Plant, Unit 2, Fuel Safety Analysis Report (FSAR).[1] The logical development of the postulated scenarios considers the selected suspect systems identified in Appendix A (see Table A-1). The deterministic analysis will show if any of the first eight Selection Criteria (presented in the Main Report) are exceeded.

The event scenario development and deterministic analysis process consists of the following steps:

1. For each event of concern (steam generator overfill, reactor coolant overcool, etc.) the limiting transient and the design basis accident (DBA), as presented in Chapter 15 of the H. B. Robinson, Unit 2 FSAR, were deterministically analyzed as necessary. These deterministic analyses on the limiting transient and the DBA are referred to as the baseline scenarios (baseline steam generator overfill scenario, baseline reactor coolant overcool scenario, etc.).

2. If nonsafety grade systems were utilized in mitigating the baseline scenario, failure of the nonsafety grade systems are postulated for the next scenario that was also deterministically analyzed. Thus, this step identifies potential failures of nonsafety grade systems and determines if the applicable Selection Criteria are exceeded.

3. Next, the baseline scenario was examined to determine if a single safety grade system failure was assumed. If not, the applicable safety grade systems from the selected suspect systems list (see Appendix A, Table A-1) were examined to determine which single safety grade system failure would produce the worst case transient or accident plant conditions for each event of concern. In some cases, it was not possible to determine which single safety grade system failure would produce the worst case transient or accident conditions; thus, it was necessary to perform a sensitivity analysis by deterministically analyzing several single safety grade system failures individually. Thus, this step identifies potential single safety grade system failures and determines if the applicable Selection Criteria are exceeded.

4. In this step, an engineering evaluation of the H. B. Robinson, Unit 2 FSAR initial plant conditions assumed for the baseline scenario was performed to identify which initial plant conditions (power, flow, etc.) could have the most significant effect on the baseline scenario. The purpose of this step was to verify or establish as necessary the worst case initial plant conditions. In some cases it was not possible to determine which one initial plant condition (reactor parameter such as power, flow, etc.) influenced the outcome of the baseline scenario the most; thus, as necessary, a sensitivity analysis was performed by varying reactor parameters and performing individual deterministic analyses.

5. The purpose of this step is to identify system failures from the selected suspect system list that would aggravate the baseline scenario the most or in other words, produce the worst-case aggravated scenario that exceeds the Selection Criteria. As in the previous two steps, it was not always possible to determine which selected suspect systems would produce the worst-case aggravated scenario; thus, as necessary, deterministic analyses were performed.

6. Systems identified as dependent on electrical power or air were deterministically analyzed next, as necessary, to determine if the Selection Criteria would be exceeded if these systems failed due to loss of electrical power or air.

The following sections describe all of the scenarios that were developed and deterministically analyzed for each event of concern.

C.1 Reactor Coolant System Overcool Scenarios

The first event of concern is reactor coolant system overcool. The concern associated with a reactor coolant system overcool event is a reactor coolant temperature decrease in excess of 100°F/hr which is also the established H. B. Robinson Technical Specification Limit.[2]

In Chapter 15 of the H. B. Robinson Unit 2 FSAR, the limiting transient and the DBA for a reactor coolant system overcool event are presented. Respectively, they are a decrease in feedwater temperature and a main steam line break. The main steam line break accident was not computer analyzed since the H. B. Robinson Unit 2 FSAR analysis assumes conservative initial conditions and the most severe safety grade failures. This accident is terminated by safety injection (SI) system initiation, reactor trip, and main steam isolation valve (MSIV) closure. The components associated with the SI system, reactor trip, and MSIV closure are safety grade, and it would take two or more safety grade component failures to prevent mitigation of a main steam line break accident. Failure of two or more safety grade components is beyond the scope of this study.

To form a basis for the reactor coolant system overcool event scenario development and deterministic analysis process that follows, the worst case decrease in feedwater temperature, as presented in Chapter 15 of the H. B. Robinson Unit 2 FSAR, will be discussed. The following discusses inadvertent opening of the feedwater heater bypass valve which diverts flow around the low pressure feedwater heaters.

Two cases were analyzed in Chapter 15 of the H. B. Robinson Unit 2 FSAR to demonstrate the plant behavior in the event of a sudden feedwater temperature reduction resulting from inadvertent opening of the bypass valve. The first case was for an uncontrolled reactor (rod control in manual) with a zero moderator coefficient, since this represents a condition where the plant has the least inherent transient capability. The second case was for a controlled reactor with a large negative moderator coefficient. Both transients were assumed to occur from full power.

For the transient without automatic control and zero moderator coefficient, the pressurizer pressure decreases as the secondary heat extraction exceeds the core power generation. The core power remains essentially constant at full load. There is an increased margin to departure from nucleate boiling (DNB) due to the accompanying reduction in average temperature. The reactor does not trip. There is a small increase in ΔT as the heat transfer increases through the steam generator.

For the transient with automatic reactor control functioning, a large negative moderator coefficient is assumed, which acts to increase power. The core power is increasing, which reduces the decrease in coolant average temperature and pressurizer pressure. Steady state conditions are reached with a minimum departure from nucleate boiling ratio (DNBR) greater than 1.59. The plant would actually be tripped by the overpower protection. There is no radioactive release, and thus, no public hazard in the event of a decrease in feedwater heating transient.

The results from Chapter 15 of the H. B. Robinson Unit 2 FSAR show that sudden changes in thermal load, caused by feedwater temperature decreases, do not cause rapid changes in core conditions or any nuclear instabilities. Parameters monitored by the protection system, such as pressure, nuclear power, and coolant temperature, vary much more slowly than during other transients for which the protection system must function. The protection system boundaries given in the H. B. Robinson Unit 2 Technical Specifications (reactor trips on high ΔT, high and low

pressure, and nuclear overpower) are more restrictive than the core DNB limits. Even at 2300 Mwt, this is a limiting transient and is well within the capability of the protection system to prevent the DNBR from decreasing below 1.30. The sequence of events for the H. B. Robinson Unit 2 FSAR analysis of this transient is presented in Table C-1.

C.1.1 Reactor Coolant System Overcool Baseline Scenario Number 1a

The first step in the reactor coolant system overcool event scenario process is to deterministically examine the effects of a decrease in feedwater temperature. After reviewing the H. B. Robinson Unit 2 FSAR analysis and the deterministic analyses performed for other events of concern, the conclusion was drawn that the reactor coolant system can not be overcooled while the reactor is at power. When the reactor is critical a decrease in feedwater temperature will result in a lower core inlet temperature which will cause an increase in reactor power which counters the decrease in coolant average temperature. Therefore, in order to produce a reactor coolant system overcool event, either reactor power will have to increase to a high reactor power trip or a reactor trip will have to be assumed at the beginning of the scenario.

On the basis of the above discussion, a baseline scenario similar to the limiting transient presented in the H. B. Robinson Unit 2 FSAR was not deterministically analyzed. Instead, the following baseline scenarios were developed based on a 10% step increase in steam flow. Several baseline scenarios were developed to provide a sensitivity study. A sensitivity study was necessary to determine how the transient would be affected if the reactor were in manual control or in automatic control.

The initial plant conditions for the Reactor Coolant System Overcool Baseline Scenario Number 1a were reactor power at 100% and in manual reactor control. For the initiating event it was assumed that a 10% step increase in steam flow occurs during normal plant operations.

TABLE C-1. H. B. ROBINSON FSAR SEQUENCE OF EVENTS FOR BYPASS OF THE FEEDWATER HEATERS FROM FULL POWER

Time (s)	Sequence of Events
0	Reactor power at 100%. Plant is in automatic reactor control. Feedwater heaters bypass valves fail open.
~38	Feedwater temperature at steam generator inlet decreases ~18°F.
~58	Reactor power peaks at ~104%.

The sequence of events for the Reactor Coolant System Overcool Baseline Scenario Number 1a is shown in Table C-2. For the deterministic analysis, the transient was initiated at 0 s by failing open the turbine control valves. At 10 s, T_{ave} starts decreasing from ~575°F but levels out at ~559°F by 125 s. In other words, T_{ave} dropped ~16°F in 115 s before leveling out. Reactor power peaks at ~2420 Mwt at 30 s but has dropped and leveled out at ~2310 Mwt at 175 s. A reactor trip does not occur which prevents the cooldown from exceeding the 100°F/hr H. B. Robinson Technical Specification Limit.

C.1.1.1 Reactor Coolant System Overcool Baseline Scenario Number 1b. The initial plant conditions for this scenario were reactor power at 102% and in automatic reactor control. For the initiating event it was assumed that a 10% step increase in steam flow occurs during normal plant operations. The only difference between this baseline scenario and the previous baseline scenario is that the reactor is in automatic control and reactor power is 102% instead of 100%. The purpose of this scenario is to determine how the transient will be affected if the reactor were in automatic control instead of manual control.

The sequence of events for the Reactor Coolant System Overcool Baseline Scenario Number 1b is shown in Table C-3. For the deterministic analysis, the transient was initiated at 0 s by opening the main turbine control valves. Primary temperatures and secondary pressures drop smoothly and then level out establishing a new steady state. Reactor power increases and then levels out at 103%. Reactor trip does not occur. T_{ave} only decreases ~1 1/2°F over 110 s. Since a reactor trip does not occur, the cooldown does not exceed the 100°F/hr H. B. Robinson Technical Specification Limit.

From these two scenarios it appears that the reactor being in manual control has the greatest affect on the transient in terms of decreasing reactor coolant temperature. However, since a reactor trip does not occur, it is not yet conclusive that having the reactor in manual control will produce the most severe transient.

TABLE C-2. SEQUENCE OF EVENTS FOR THE REACTOR COOLANT SYSTEM OVERCOOL BASELINE SCENARIO NUMBER 1a

Time (s)	Sequence of Events
0.0	Reactor power is 100% and in manual control. A 10% step increase in steam flow occurs (steam governor valve starts to open).
8.0	Pressurizer heaters turn on.
56.0	Steam governor valve fully open.
235.0	Reactor coolant temperature and power have level out. Overcool does not occur. End of calculation.

TABLE C-3. SEQUENCE OF EVENTS FOR THE REACTOR COOLANT SYSTEM OVERCOOL BASELINE SCENARIO NUMBER 1b

Time (s)	Sequence of Events
0.0	Reactor is at 102% power (2346 Mwt) with rod control in automatic.
110.0	Reactor power reached new steady state power of ~2370 Mwt (103% full power).
125.0	Reactor average temperature reached a new equilibrium value of 579°F.
140.0	Reactor power peaked at 2371 Mwt.

C.1.2 Reactor Coolant System Overcool Scenario Number 2

The second step in the event scenario development process is to determine if any nonsafety grade systems were used to mitigate the Reactor Coolant System Overcool Baseline Scenarios Numbers 1a and 1b, and if any nonsafety grade systems were used, to postulate their failure and deterministically analyze the resultant sequence. The evaluation of the overcool baseline scenarios indicated that the main factors in mitigating the effects of these transients are the inherent reactor feedback mechanisms. As the reactor inlet temperature began to decrease, the resultant positive reactivity addition would increase reactor power which would stop the temperature decrease and establish an equilibrium condition at a higher reactor power. One nonsafety grade system was found to have operated during the overcool baseline scenarios that may have aided in mitigating the transients, and that system is the pressurizer pressure control system. The pressurizer heaters operated during the transients in an attempt to maintain pressurizer pressure. The effects of these heaters on the overcool transients are assumed to be minimal, yet a separate scenario was analyzed to verify that this assumption is true.

The scenario was initiated at 67% reactor power with rod control in manual and all other control systems in automatic. The main turbine control valves were failed fully open to start the transient. The pressurizer heaters were off and failed to operate during the entire calculation. This scenario is identical to Reactor Coolant System Overcool Scenario Number 4b (Section C.2.4.1) except for the failure of the pressurizer heaters. The results of these two scenarios are almost identical; there is no measurable difference between the loop average temperature plots from the deterministic analysis of the two transients. Therefore, it can be concluded that the failure of the pressurizer heaters did not make a significant contribution to the mitigation of any of the analyzed reactor coolant system (RCS) overcool transients.

The sequence of events for the Reactor Coolant System Overcool Scenario Number 2 is presented in Table C-4. The transient starts with an increase in steam flow, which causes a drop of RCS temperature and pressure as more energy is removed from the RCS than is being supplied by the reactor. As the temperatures drop, positive reactivity is added to the core which increases the reactor power. These trends continue until the maximum steam flow is reached and then the RCS temperature, pressure, and reactor power all settle out at new equilibrium values.

C.1.3 Reactor Coolant System Overcool Scenario Number 3a

The third step in the event scenario development process is to examine the Reactor Coolant System Overcool Baseline Scenarios Numbers 1a and 1b to determine if a single safety grade system failure was assumed. In this case, a single safety grade system failure had not been assumed.

The selected suspect systems list for RCS overcool (Table C-5) was reviewed for the purpose of identifying safety grade system failures that could contribute to a reactor coolant system overcool event. Of the systems listed in Table C-5, eight are safety grade systems: pressurizer overpressure protection system, high head safety injection system, residual heat removal system, reactor protection system, steamline overpressure protection system, main steam system (MSIVs), auxiliary feedwater system, and component cooling water system.

Inadvertent actuation of the high head safety injection system can cool the RCS by injecting cool water into the three RCS loops. During periods of normal plant operation inadvertent injection cannot occur since the shutoff head of the high head SI pumps is approximately 1500 psia while the RCS nominal pressure is 2250 psig. If, during power operation, the RCS pressure drops below 1500 psia so injection can occur, the ECCS would already have been initiated as designed to protect the plant from the accident condition that caused the pressure drop, therefore, inadvertent initiation could not occur. During low temperature and low pressure operations it is possible for the high head safety injection pumps to

TABLE C-4. SEQUENCE OF EVENTS FOR REACTOR COOLANT SYSTEM OVERCOOL SCENARIO NUMBER 2

Time (s)	Event
0.0	Turbine control valves began to open.
12.0	Reactor power began to increase due to the inherent core feedback mechanisms.
16.0	Reached the maximum steam flow (3280 lbm/s).
19.0	The turbine control valves are fully open.
100.0	Stopped the calculation.

TABLE C-5. SELECTED SUSPECT SYSTEMS FOR REACTOR VESSEL OVERCOOL EVENTS

System	Failure Mode	Loss of Electrical Power or Air	Safety Grade	Postulated Effects
Reactor coolant system and pumps	Inadvertent pump start		No	An inadvertent starting of an idle pump could contribute to a reactor overcool.
Pressurizer overpressure protection system	Inadvertent PORV or safety valve opening		Yes	An inadvertent valve opening could cause an overcool by causing a loss of coolant which requires replacement by colder makeup.
High head safety injection system	Inadvertent start		Yes	An inadvertent start could contribute to an overcool by adding cold water to the reactor coolant system.
Residual heat removal system	Inadvertent start		Yes	An inadvertent start could contribute to an overcool by adding cold water to the reactor coolant system.
Chemical and volume control system	High makeup or low letdown flow rates	1, 2	No	A high makeup or low letdown flow rate could contribute to an overcool by adding an increased amount of cold makeup water into the RCS.
Reactor protection system	Inadvertent reactor trip	1	Yes	An inadvertent reactor trip could contribute to an overcool by causing a power decrease.
Control rod drive system	Inadvertent rod insertion	1	No	An inadvertent rod insertion could contribute to an overcool by causing a power decrease.
Feedwater and condensate systems	High feed flow or low feedwater temperature	2	No	High feed flow or low feedwater temperature could contribute to an overcool by increasing the heat transfer from the reactor coolant system.
Steamline overpressure protection system	Inadvertent safety valve or PORV opening		Yes	An inadvertent safety valve or PORV opening could contribute to an overcool by causing an increased heat transfer from the reactor coolant system.
Main steam system	Inadvertent MSIV opening		Yes	An inadvertent MSIV opening could contribute to an overcool by causing an increased heat transfer from the reactor coolant system.

TABLE C-5. (continued)

System	Failure Mode	Loss of Electrical Power or Air[a]	Safety Grade	Postulated Effects
Turbine generator system	Inadvertent control valve opening		No	An inadvertent control valve opening could contribute to an overcool by causing an increased steam flow and heat transfer from the reactor coolant system.
Auxiliary feedwater system	Inadvertent start	1	Yes	An inadvertent start could contribute to overcool by adding cold water to the steam generator which increases the heat transfer from the reactor coolant system.
Steam generator	Tube rupture		No	This system could contribute to an overcool, however, it is an independent study and will be presented separately.
Steam generator blowdown system	High flow		No	A high steam generator blowdown flow could contribute to an overcool by removing water from the steam generator and requiring colder makeup.
Auxiliary steam system	High flow		No	A high steam flow could contribute to an overcool by requiring a cold water makeup.
Steam dump system	Inadvertent valve opening		No	An inadvertent steam dump valve opening can contribute to an overcool by increasing the steam flow which causes an increase in heat transfer from the reactor coolant system and requires cold makeup water to replace the loss of coolant.
Component cooling water system	High flow		Yes	A high component cooling water system flow could contribute to an overcool while RHR is in operation by increasing heat transfer from the reactor coolant.

a. Loss of electrical power--1, Loss of air--2.

inject cool water into the RCS. The pump breakers are racked out when the RCS temperature is decreased below 350°F. However, there is a time period during heatup and cooldown evolutions when the pumps are enabled and the RCS pressure is below the high head SI pump shutoff head. If an inadvertent SI actuation occurred during that window of vulnerability it would result in the injection of cool water to the RCS. Reactor Coolant System Overpressure Sequence Number 2 (Section 2.5.4) analyzed an inadvertent safety injection actuation system (SIAS) operation with the RCS at 350°F and 265 psia, this analysis showed that this failure mode will not result in a 100°F/hr. cooldown of the RCS.

Inadvertent start of a residual heat removal (RHR) pump cannot inject water into the RCS until the RCS pressure drops below the shutoff head of the RHR pumps (approximately 150 psia). When RCS pressure is less than 150 psia, the RHR system should be in the cooldown mode where the operator is directly controlling the cooldown rate and the RCS temperature is low enough that a 100°F/hr. cooldown would be improbable.

Inadvertent opening of an MSIV could possibly result in an increased steam flow and resultant cooldown of the RCS. This failure mode would involve a procedure violation during power operation since all three MSIVs are required to be open and one would have to be shut in order to inadvertently open. During shutdown, this failure mode would have little or no affect on the RCS temperature since all of the steam loads would be isolated and the only flow that would occur would be that involved in pressurizing the main steam headers. Additional information is provided for this and other systems in Table C-6, Justification For Not Utilizing Aggravating Systems In Additional RCS Overcool Computer Analyses.

A high flow rate is the failure mode of concern for the component cooling water system. This system would have minimal effect on the RCS unless the plant is in the cooldown mode using the RHR system. RHR cooldown is not placed into operation until the RCS is at 350°F and 375 psig during plant cooldown. The cooldown at this point is a controlled

TABLE C-6. JUSTIFICATIONS FOR NOT UTILIZING AGGRAVATING SYSTEMS IN ADDITIONAL RCS OVERCOOL COMPUTER ANALYSES

Suspect Aggravating System	Failure Mode	Justification
Reactor coolant system and pumps	Inadvertent pump start	Having one or more reactor coolant pumps (RCPs) idle during plant operation or during other plant operating modes when the RCS temperature is high enough to make a 100°F/hr. cooldown rate feasible would involve a violation of plant operating procedures and/or Technical Specifications. There are several other factors that would tend to minimize an inadvertent RCP start: The RCS does not have loop isolation valves and so the back flow caused by the running RCPs in the other loops would prevent a large differential temperature from developing. A reactor trip would be actuated if any of the three RCPs were stopped when power is greater than 10%.
Pressurizer overpressure protection system	Inadvertent power operated relief valve (PORV) or safety valve opening	An inadvertent opening of a PORV or a safety valve results in a release of reactor coolant. The loss of coolant would cause a decrease in RCS pressure which would cause an initiation of the emergency core cooling system (ECCS). ECCS flow into the RCS will cooldown the RCS and could result in an overcool event. However, the loss of coolant accident (LOCA) is a serious accident that must be mitigated even if that mitigation results in an RCS overcool transient. A failure open of a pressurizer PORV was evaluated in the H. B. Robinson FSAR and was bounded by the double ended could leg guilotine break analyzed in the FSAR and in Section C-6 of this report. Therefore, this failure mode will not be further analyzed for an RCS overcool event.
High head safety injection system	Inadvertent start	During normal plant operation, an inadvertent high head safety injection start would have no effect on the plant since the RCS would be at approximately 2250 psig and the shutoff head of the high head safety injection pumps is approximately 1500 psig. When RCS pressure is lowered during shutdowns, at 2000 psig, the low pressurizer pressure and high steamline P trips are blocked for SIAS, and at 350°F the high head SI pump breakers are racked out. Therefore, there is only a small operating window in which this failure mode could result in a plant cooldown. Reactor Coolant System Overpressure Sequence Number 2 (Section 2.5.4) analyzed an inadvertent SIAS operation while in this window of vulnerability and the analysis indicated that RCS overcool is not a problem.

TABLE C-6. (continued)

Suspect Aggravating System	Failure Mode	Justification
Residual heat removal system	Inadvertent start	The shutoff head for the RHR pumps is approximately 150 psia and so they cannot inject water into the RCS unless RCS pressure drops below 150 psia. For any plant condition where RCS pressure would be this low, the RHR would be operating in the recirculation mode and the RCS temperature would be low enough that an overcool could not occur. Therefore, an inadvertent start of an RHR pump could not cause an RCS overcool event and would be an insignificant contributor.
Chemical and volume control system (CVCS)	High makeup or low letdown flow	The CVCS is a relatively low volume system (maximum charging capacity is approximately 230 gpm and maximum letdown flow is 166 gpm) and the charging pump speed is automatically controlled to maintain the pressurizer level at the programmed value. A high makeup or low letdown flow would cause a pressurizer level increase and could cause a cooldown of the RCS, however, due to the small flowrates associated with this system and the relatively small temperature differential (due to the preheating of the charging flow in the regenerative heat exchanger), this failure mode would have an insignificant effect on an overcool.
Reactor protection system	Inadvertent reactor trip	A reactor trip, by itself, cannot cause an overcool of the RCS. A reactor trip is very effective as an aggravator since it is almost essential to have the reactor trip in order to achieve an overcool. Due to the inherent feedback mechanisms in the reactor, a decrease in RCS temperature will add positive reactivity which results in an increase in reactor power and a temperature increase. Therefore, unless the reactor is tripped, a 100°F/hr. cooldown rate cannot be maintained. An inadvertent reactor trip, along with a second failure that resulted in the removal of heat from the RCS was analyzed as Reactor Coolant System Overcool Scenario Number 3a (Section C.1.3).
Control rod drive system	Inadvertent rod insertion	This failure mode would result in a decrease in the reactor average temperature, but it would only decrease a fraction of 100°F and could not cause an RCS overcool by itself. As a contributor, this failure could aggravate the cooldown of the RCS, however, without a reactor trip, an overcool cannot occur, and with a reactor trip this failure mode cannot occur.

TABLE C-6. (continued)

Suspect Aggravating System	Failure Mode	Justification
Feedwater and condensate systems	High feedwater flow or low feedwater temperature	High feedwater flow failures have been analyzed in several of the scenarios discussed in Sections 2.5 and C.7 and they did not result in overcool of the RCS. Low feedwater temperature was analyzed by Reactor Coolant System Overcool Scenario Number 3c in Section C.1.3.2, and it did not result in overcool of the RCS.
Steamline overpressure protection system	Inadvertent opening of a PORV or safety valve	This failure mode was analyzed by Reactor Coolant System Overcool Scenario Number 3b in Section C.1.3.1 and was found to not be a concern for RCS overcool as long as the reactor remains critical. Reactor Coolant System Overcool Sequence Number 2 (Section 2.5.2) analyzed this failure with the reactor subcritical and showed that Selection Criterion 1 was exceeded.
Main steam system	Inadvertent opening of an MSIV	For an MSIV to be closed during power operation would require violation of General Procedure 4, which would be an operator error and is, therefore, beyond the scope of this study. For an MSIV to open during shutdown would cause no problem since there would not be any steam flow paths open to draw off steam to cool the RCS. A failure closed with a subsequent reopening of an MSIV was not analyzed for the initial failure closed would result in an SIAS, reactor trip, turbine trip, etc.
Turbine generator system	Inadvertent opening of the turbine control valve	This failure mode was analyzed in several reactor coolant system overcool scenarios in this section (See C.1.1, C.1.1.1, C.1.2, C.1.3.1, C.1.3.2, C.1.4, and C.1.4.1).
Auxiliary feedwater system	Inadvertent start	This failure mode was used as an aggravator for Reactor Coolant System Overcool Scenario Number 3c (Section C.1.3.2) and did not result in a significant reduction in RCS temperature.
Steam generator	Tube rupture	See Steam Generator Tube Rupture Sequence Numbers 1 and 2 in Section 2.5.7 and 2.5.8.
Steam generator blowdown system	High flow	This system failure mode could aggravate a cooldown of the RCS. However, the system piping is of relatively small diameter and the heat removed would be insignificant and would be bounded by the failure open of turbine control valves or failure open of a steamline PORV or safety valve.

TABLE C-6. (continued)

Suspect Aggravating System	Failure Mode	Justification
Auxiliary steam system	High flow	This system failure mode could aggravate a cooldown of the RCS. However, the system piping is of relatively small diameter and the heat removed would be insignificant and would be bounded by the failure open of turbine control valves or failure open of a steamline PORV or safety valve.
Steam dump system	Inadvertent opening of steam dump valves	See Reactor Coolant System Overcool Sequence Number 1 (Section 2.5.1).
Component cooling water system	High flow	The RHR system is not placed into the cooldown mode during plant cooldown until the RCS temperature is 350°F and pressure is 375 psig. From that point the cooldown is a continuously controlled operation where the operator regulates the rate of temperature decrease carefully to maintain the rate within the Technical Specification limit. Even if a component cooling water system failure resulted in a high flow rate, the operator would have to fail to follow his procedure to allow a 100°F/hr. cooldown to occur. Operator error is outside of the scope of this study.

evolution by the operator and even if system failures occur, an operator error would be required to overcool the RCS. Operator errors are beyond the scope of this study.

A failure of the reactor protection system that results in a spurious reactor trip was analyzed for RCS Overcool Scenario Number 3a. The initial conditions for the scenario are a power level of 102% with all control systems in automatic. Since a reactor trip by itself does not result in a reactor cooldown, another failure must be postulated to remove the energy from the system to cool it down. After a reactor trip the steam dump system opens the dump valves to cool the RCS to the no load T_{ave} (547°F), therefore, one of the steam dump valves was assumed to stick in the open position to provide a cooldown mechanism.

A sequence of events for RCS Overcool Scenario Number 3a is provided in Table C-7. The failure open of the steam dump valve provided a smooth cooldown of the RCS as it removed more energy than was being added by the decay heat from the core. The pressurizer heaters were assumed to fail, so the RCS pressure also decreased as the plant cooled down. A stable cooldown rate of 6.6°F/minute was established early in the transient, therefore, at 10 minutes the RCS would be approximately 93°F lower than the initial temperature. At this time it is assumed that the operators would take actions to stop the cooldown so the 100°F limit would not be exceeded. However, this scenario demonstrates that with the reactor subcritical, an RCS overcool will take place if a failure occurs that removes sufficient energy from the secondary (see Reactor Coolant System Overcool Sequence Number 2, Section 2.5.2).

C.1.3.1 Reactor Coolant System Overcool Scenario Number 3b. This scenario examines the failure open of a steamline safety valve. The initial plant conditions are a plant power level of 67% with all control systems in automatic.

TABLE C-7. SEQUENCE OF EVENTS FOR REACTOR COOLANT SYSTEM OVERCOOL SCENARIO NUMBER 3a

Time (s)	Event
0.0	Reactor tripped due to assumed fault. Turbine trips. Steam dump valves open. Main feedwater valves start to close. Motor driven auxiliary feedwater pumps start.
6.0	A steam dump valve sticks open (fails to close).
8.0	Main feedwater (MFW) isolation valves are closed.
27.0	Turbine driven auxiliary feedwater pump starts.
100.0	Stable cooldown of 6.6°F/minute reached, stopped calculation.

The transient is initiated by a failure open of the turbine control valves and aggravated by a simultaneous failure open of a steamline safety valve. This scenario is the same as Reactor Coolant System Overcool Scenario Number 4a (Section C.1.4) except for the aggravating failure. The reactor is not tripped during this transient and so the inherent feedback mechanisms mitigate the event and cause a new steady state to be established at a higher power level. Due to the steam flow out of the safety valve, this scenario resulted in a higher power level and a lower T_{ave} than Scenario Number 4a, however, all other parameters responded the same for this transient as they did for Scenario Number 4a. The reactor T_{ave} only decreased 7°F when it bottomed out and began to increase. This is more severe than scenario Number 4a, which had a T_{ave} decrease of only 4°F, however, neither scenario presents a problem as far as RCS overcool is concerned.

The sequence of events for Reactor Coolant System Overcool Scenario Number 3b is presented in Table C-8.

C.1.3.2 Reactor Coolant System Overcool Scenario Number 3c. This scenario examines RCS Overcool Scenario Number 4a (opening of the turbine control valves at 67% power with the rod control in automatic) aggravated with one safety grade system failure and two nonsafety grade system failures. The safety grade system failure assumed for this scenario is the inadvertent start of the motor driven auxiliary feedwater (AFW) pumps at time t = 0.0. The nonsafety grade failures are: an instantaneous loss of extraction steam to both trains of high pressure feedwater heaters, and failure of the pressurizer heaters.

The sequence of events for Reactor Coolant System Overcool Scenario Number 3c is provided in Table C-9. This event is initiated at 67% reactor power with all control systems in automatic by simultaneously failing the turbine control valves open, the auxiliary feedwater pumps on, and the extraction steam off to the high pressure feedwater heaters. This transient is similar to Overcool Scenario 4a for the first minute and a

TABLE C-8. SEQUENCE OF EVENTS FOR REACTOR COOLANT SYSTEM OVERCOOL SCENARIO NUMBER 3b

Time (s)	Event
0.0	Main turbine control valves begin to open. A steamline safety valve opens. Rod control system starts rod withdrawal.
19.0	Main turbine control valves are fully open.
40.0	Controlling rod bank is fully withdrawn.
48.0	Minimum T_{ave} of 559°F is reached.
75.0	The calculation was stopped.

TABLE C-9. SEQUENCE OF EVENTS FOR REACTOR COOLANT SYSTEM OVERCOOL SCENARIO NUMBER 3c

Time (s)	Event
0.0	Transient initiated by opening the turbine control valve at 200%/min. Additionally, both motor-driven auxiliary feedwater pumps were started, and the extraction steam to both trains of high pressure feedwater heaters was isolated.
14.5	Reached the maximum feedwater flow rate.
15.5	The maximum turbine control valve flow rate was achieved.
47.0	The turbine control valve steam flow rate is steady.
50.0	The feedwater flow rates are steady.
75.0	Reactor power exceeded the heat transfer rate to the SG secondaries.
150.0	The main feedwater system tripped due to low condensate pump discharge pressure.
182.0	Reactor tripped on low feedwater flow rate and < 30% SG NR level (SGC).
195.0	MSIVs closed on 2/3 steam line flow rates > setpoint flow rate and 2/3 primary average temperatures < 543°F. Turbine-driven auxiliary feedwater is initiated on 2/3 SG NR levels < 15%.
200.0	The reactor vessel downcomer temperature reached minimum of 523°F.
240.0	Calculation stopped.

half with the increased steam flow and feed flow reducing RCS temperature until the core temperature coefficients result in an increase in reactor power which subsequently increases the RCS temperature. At 182 s the reactor is tripped from low steam generator (SG) level and high steam flow/feed flow mismatch. The reactor trip results in a rapid temperature decrease until 195 s when the MSIVs are closed, thereby shutting off all the steam flow. The reactor vessel downcomer reached the minimum temperature of 523°F at 200 s and begins to slowly increase.

The postulated aggravating system failures analyzed resulted in a transient that caused a reactor trip, which has been shown to be essential in order to have an RCS cooldown of 100°F/hr., however, the perturbation caused by the failures also lead to the closure of the MSIVs which in turn mitigated the transient.

C.1.3.3 Reactor Coolant System Overcool Scenario Number 3d. The final safety grade system failure to be evaluated for the overcool event is a failure open of a pressurizer safety valve or power operated relief valve (PORV). Since a failure open of a pressurizer PORV or safety valve is a loss of coolant accident (LOCA) which is mitigated by the emergency core cooling system (ECCS) and reactor protection system, it was decided that this failure mode would not be deterministically analyzed as an aggravating system failure since the cooldown caused by the actuation and proper operation of the mitigative systems is desirable and is the designed consequence of the operation of these systems. However, a failure open of a pressurizer PORV was analyzed in the pressurized thermal shock (PTS) study for Unresolved Safety Issue (USI) A-49. That analysis is discussed below as Reactor Coolant System Overcool Scenario Number 3d.

The event is initiated by a failure open of a pressurizer PORV from 100% reactor power with all control systems in automatic. The open PORV results in a decrease in RCS pressure and pressurizer level as steam is released from the pressurizer. After 33.4 s a reactor trip is actuated by a high reactor ΔT in two out of three of the RCS loops. The RCS pressure dropped off more rapidly after the reactor trip. After 113 s the pressure

decreased to the point where the high head safety injection pumps began injecting coolant into the RCS loops. In this transient operator action was taken at 139 s to trip the RCPs when the RCS pressure fell below 1300 psig. This is not consistent with the proposed ANSI N660 guidelines[3], however, it is consistent with the guidelines established for the PTS study. After 10 minutes had elapsed, the operators were assumed to take action to stop the leak by closing the PORV isolation valve. The minimum temperature of 509°F was not reached until approximately 6 minutes later at 947 s.

A sequence of events for Reactor Coolant System Overcool Scenario Number 3d is provided in Table C-10. This transient did not result in an RCS overcool even with the loss of energy from the open PORV and the injection of cool water by the ECCS.

C.1.4 Reactor Coolant System Overcool Scenario Number 4a

The fourth step in the event scenario development process is to establish whether or not the worst case initial plant conditions were used in the H. B. Robinson FSAR for the reactor coolant system overcool event.

The H. B. Robinson Unit 2 FSAR analysis of bypass around the low pressure feedwater heaters assumed an initial power of 100% of rated power (2300 Mwt). This is the highest reactor power level that will normally be seen during plant operation. To determine if a higher initial power can increase the severity of the RCS overcool events, Reactor Coolant System Overcool Scenario Number 1b was evaluated using an initial power level of 2346 mwt (102% full power). The higher power did not result in the transient being more severe than similar transients at the lower power level (2300 Mwt).

The H. B. Robinson Unit 2 FSAR analysis evaluated two different initial conditions, the controlled reactor with rod control in automatic and a large negative moderator coefficient and a reactor with rod control

TABLE C-10. SEQUENCE OF EVENTS FOR REACTOR COOLANT SYSTEM OVERCOOL SCENARIO NUMBER 3d

Time (s)	Event
0.0	PORV opened.
33.4	Reactor tripped on 2/3 reactor high delta temperature; turbine stop valve closed; feedwater valves began to close.
34	Steam dump valve opened.
37	Steam dump valve closed.
52	Feedwater valves closed.
54	MFW pumps tripped.
72	Steam dump valve opened.
113	High head safety injection flow initiated on low primary system pressure.
139	Reactor coolant pumps tripped by operator.
180	Reactor vessel upper head fluid saturated and began to flash to steam.
272	Steam dump valve control shifted to steam pressure control (SPC) mode, dump valve closed.
278	Normalized pressurizer level went off scale high.
600	PORV block valve closed.
947	Reached minimum reactor vessel downcomer temperature of 509°F.
1490	Reactor vessel upper head refilled with liquid.
1506	Primary system pressure rose above the high head safety injection pump shutoff head, high head safety injection flow stopped.
1840	Steam dump valves opened.
2088	Pressurizer safety relief valve opened, then immediately closed.
2200	End of calculation.

in manual and a zero moderator coefficient. Neither of these two extreme cases resulted in a significant problem and this event did not appear to be overly sensitive to reactor control conditions.

The initial conditions assumed for Reactor Coolant System Overcool Baseline Scenarios Numbers 1a and 1b are 100% and 102% full power, respectively. These scenarios were initiated by failing the turbine control valves open at high powers with the expectation that the high neutron level trip point would be exceeded which would trip the reactor and prevent the inherent feedback mechanisms from increasing power and restricting the temperature decrease. The reactor power, however, did not increase enough to reach the high neutron level trip point and an overcool did not develop. The next scenario was initiated from a reactor power of 67% to allow greater movement of the turbine control valve to produce a greater increase in steam flow.

Reactor Coolant System Overcool Scenario Number 4a was initiated at 67% reactor power with all control systems operating in automatic. This scenario was analyzed to determine if a failure open of a turbine control valve transient is more severe at lower initial reactor power levels. The failure resulted in an increased steam flow which reduced RCS temperature resulting in an increase in reactor power until a new steady state condition is established at a higher reactor power. The transient was almost identical to Reactor Coolant System Overcool Baseline Scenario Number 1b with the exception that the decrease in T_{ave} was more severe (4°F) for the transient initiated at 67% power than it was for the transient initiated at 102% power (1.5°F). It can be seen that a failure open of a turbine control valve is more severe at lower powers than at higher powers, however, it is apparent from the transient results that, even if the event were initiated at the no load steady state power level, the cooldown would not approach the 100°F/hr. limit.

A sequence of events for Reactor Coolant System Overcool Scenario 4a is presented in Table C-11.

TABLE C-11. SEQUENCE OF EVENTS FOR REACTOR COOLANT SYSTEM OVERCOOL SCENARIO NUMBER 4a

Time (s)	Event
0.0	The main turbine control valve begins to open.
0.3	Control rod bank begins to be withdrawn.
19.0	The main turbine control valve is fully open.
39.0	The control rod bank is fully withdrawn.
44.0	The RCS loops average temperature reaches minimum value and begins to increase.
50.0	The calculation is stopped.

C.1.4.1 Reactor Coolant System Overcool Scenario Number 4b. Reactor Coolant System Overcool Scenario Number 4a above was initiated at 67% reactor power with rod control in automatic. With rod control in automatic the control rod withdrawal to compensate for the decreasing T_{ave} should augment the temperature feedback coefficients to rapidly raise reactor power. Since the rod control in automatic did not produce a reactor trip, the net effect on the transient was nonconservative since it helped maintain the RCS temperatures. Therefore, Reactor Coolant System Overcool Scenario Number 4b was initiated from 67% power with rod control in manual.

A sequence of events for Reactor Coolant System Overcool Scenario Number 4b is presented in Table C-12. This transient was almost identical to Reactor Coolant System Overcool Scenario Baseline Scenario Number 1a except it is more severe due to the lower initial power level. The scenario initiated from 67% power resulted in a 19°F cooldown while the scenario started from 100% power had a 16°F reduction in T_{ave}. As concluded in Section C.1.4, while a lower power level is more severe for a failure open of the turbine control valves, it does not increase the cooldown sufficiently to result in a 100°F/hr. RCS cooldown.

C.1.5 Reactor Coolant System Overcool Scenario Number 5

The purpose of this step is to identify system failures from the selected suspect systems list (Table C-5) that would have the greatest effect in aggravating the baseline scenario, or in other words, produce the worst case scenario in an attempt to exceed Selection Criterion 1. By reviewing the scenarios that have been developed and analyzed, it was determined that all potential aggravating system failures had already been addressed. Table C-6 shows the applicable scenarios that have been developed and analyzed for each selected suspect system or provides the justification why further scenario development and deterministic analysis is not necessary.

TABLE C-12. SEQUENCE OF EVENTS FOR REACTOR COOLANT SYSTEM OVERCOOL SCENARIO NUMBER 4b

Time (s)	Event
0.0	The main turbine control valve started to open.
12.0	Reactor power begins to increase due to the core temperature coefficients.
19.0	The main turbine control valve is fully open.
150.0	The RCS loop average temperatures are essentially stable.
225.0	Calculation is stopped.

C.1.6 Systems Susceptible to Loss of Electrical Power or Loss of Air

The final step in the event scenario development process is to analyze those systems dependent on electrical power or air. There are several of the selected suspect systems that, upon a loss of electrical power or air, transfer to their failure mode of concern as identified in Table C-5. These failure modes that could potentially create a reactor coolant system overcool event have either been previously analyzed or are bounded by other scenario analyses. Table C-6 shows the applicable scenarios that have been developed and analyzed for these systems or provides the justification why further scenario development and deterministic analysis is not necessary.

C.1.7 Summary of Reactor Coolant System Overcool Scenarios

One insight that was gained from this evaluation is that a reactor coolant system overcool will not occur if the reactor is critical due to the effects of the core temperature coefficients. It was also shown that if the reactor trips or is initially subcritical an overcool can occur if there is a source of energy removal equal to or greater than one open steam dump valve. The only system failure that resulted in both a reactor trip and a reactor coolant system overcool is a failure open of the steam dump valves at 102% reactor power. Due to the system design, operating procedures, or administrative controls the ECCS failures could not produce a reactor coolant system overcool unless the system was operating to mitigate a LOCA. If the ECCS is operating during a LOCA, the operation is intended and the consequences of that operation are acceptable when compared with the consequences of a failure of the system to operate.

C.2 Reactor Coolant System (RCS) Pressure Increase Scenarios

The next event of concern is a reactor coolant system pressure increase. The concern of a reactor coolant system pressure increase event is a pressure increase that is greater than design pressure plus 10%,.or in other words, if reactor coolant system pressure increases to greater than 2750 psia.

In Chapter 15 of the H. B. Robinson Steam Electric Plant, Unit 2 FSAR, the limiting transient for a reactor coolant system pressure increase event is an instantaneous loss of steam load without automatic steam dump or a direct reactor trip. There is no DBA identified in Chapter 15 of the H. B. Robinson FSAR for a reactor coolant system pressure increase event. To form a basis for the reactor coolant system pressure increase event scenario development and analysis process that follows, the instantaneous loss of steam load without automatic steam dump or direct reactor trip transient, as presented in Chapter 15 of the H. B. Robinson FSAR, will be discussed first. The following is a discussion of this transient as presented in Chapter 15 of the H. B. Robinson FSAR.

The loss of external electric load incident is analyzed as a complete and instantaneous loss of steam load on the Nuclear Steam Supply System without automatic steam dump or a direct reactor trip. As such, it constitutes the most severe transient with respect to overpressurization of the RCS and steam generator.

The loss of external electrical load may result from an abnormal increase in network frequency, or an accidental opening of the main breaker from the generator which fails to cause a turbine trip, but causes a rapid large load reduction by the action of the electro-hydraulic turbine control.

The plant is designed to accept a 50 percent loss of export load without actuating a reactor trip. The automatic steam bypass system, with 40 percent dump capacity to the condenser and 10 percent dump capacity to the atmosphere, is able to accommodate this abnormal load rejection by

reducing the transient imposed upon the RCS. The reactor power is reduced to the new equilibrium power level at a rate consistent with the capability of the rod control system. The pressurizer relief valves may be actuated, but the pressurizer safety valves and the steam generator safety valves are not actuated in this case.

In the event the steam dump valves fail to open following a large load loss, the steam generator safety valves are actuated and the reactor may be tripped by the high pressurizer pressure signal. The steam generator shell side pressure and reactor coolant temperature increase rapidly. The pressurizer safety valves are sized to protect the RCS against overpressure without taking credit for the steam bypass system.

The most likely source of a complete loss of load on the Nuclear Steam Supply System (NSSS) is a trip of the turbine-generator. In this case, there is a direct reactor trip signal derived from turbine autostop oil pressure (a two out of three signal). Reactor coolant temperatures and pressure do not significantly increase if the steam bypass system and pressurizer pressure control system are functioning properly. However, the plant behavior is also evaluated for a complete loss of load from full power without a direct reactor trip, primarily to show the adequacy of the pressure relieving devices and also to show that no core damage occurs. The RCS and steam system pressure relieving capacities are designed to assure safety of the plant without requiring the automatic rod control, pressurizer pressure control and/or steam bypass control systems.

In the event of a complete loss of load while the reactor is operating at full power, there would be a significant reduction in the rate of heat removal from the primary coolant system. A positive moderator temperature coefficient will enhance the primary coolant heatup and result in reducing the margin to departure from nucleate boiling (DNB) and increasing the peak primary system pressure. The acceptance criteria for this event are:

1. The pressurizer safety valves shall limit RCS pressure to a value below the American Society of Mechanical Engineers (ASME) Code safety limit of 110 percent of design pressure (2750 psia)[4], and

2. MDNBR ≥ 1.30 during the transient.

The most probable cause of a rapid loss of load is a turbine trip. This analysis considers plant behavior upon a trip of the turbine-generator without a direct reactor trip in order to demonstrate that the primary coolant system is adequately protected during a complete loss of load transient.

Two cases were analyzed to determine the closest approach to each of the above criteria. Transient responses are calculated from 102 percent of rated power. Beginning of cycle (BOC) kinetic coefficients were assumed, with a 0.8 multiplier applied to the Doppler coefficient and a 1.25 multiplier applied to the moderator temperature coefficient.

The worst case with regard to peak primary side pressure (Case 1) is the transient initiated from 2280 psia (30 psia above the nominal value) with no pressurizer relief, pressurizer spray, steam dump, or steam bypass allowed. The peak pressurizer pressure reached during this transient is 2545 psia. The safety valve opens at 2500 psia. The peak pressure is well below the design limit. The reactor scrammed on high pressurizer pressure at about 7 s after the initiation of the transient. The sequence of events for the H. B. Robinson FSAR analysis for an instantaneous loss of steam load is presented in Table C-13.

The case yielding the lowest minimum departure from nucleate boiling (MDNBR) (Case 2) is the transient initiated from 2220 psia, with the pressurizer spray and relief valves operable but the steam dump and steam bypass to the condenser assumed inoperable. This results in a combination of low primary pressure and low inlet subcooling giving an MDNBR of 2.08. The reactor trips on a high primary pressure signal. The relief valve opened but the safety valve is not actuated.

TABLE C-13. H. B. ROBINSON FSAR SEQUENCE OF EVENTS FOR LOSS OF STEAM LOAD

Time (s)	Event
7	Reactor trip from high pressurizer pressure.
8	Steamline safety relief valve opens.
9	Pressurizer safety relief valve opens at 2500 psia.
9.5	T_{AVE} peaks.
10.5	Pressurizer pressure peaks at 2545 psia.

The results of the loss of load transient analysis demonstrate that the peak primary system pressure does not exceed 2545 psia and the minimum departure of nucleate boiling ratio (DNBR) does not drop below 1.75. In none of the cases were the H. B. Robinson Technical Specification limits of peak primary pressure (≤2750 psia) and MDNBR (≥ 1.30) violated.

C.2.1 Reactor Coolant System Pressure Increase Baseline Scenario (Number 1)

The Reactor Coolant System Pressure Increase Baseline Scenario (Number 1) is similar to the H. B. Robinson FSAR analysis presented above. Initial reactor power for the analysis was 102% full power, and the following systems or components were not allowed to operate to help mitigate the transient: steam dump system, pressurizer spray, pressurizer level control, pressurizer PORVs, one pressurizer safety valve, the reactor trip from turbine trip, and the secondary PORVs.

The transient was initiated by tripping the turbine and closing the turbine stop valve which simulates a complete loss of load on the turbine. This initiating event, along with the failure of steam dump and steam bypass flow, results in almost a total stoppage of secondary steam flow which causes a rapid increase in secondary pressure and decrease in primary to secondary heat transfer. The reduction in the heat transfer in the steam generators causes primary temperature to rapidly increase and the resultant insurge into the pressurizer causes the RCS pressure to rise to the high pressure setpoint that initiates a reactor trip. The sequence of events for this scenario is provided in Table C-14.

This transient was terminated by a reactor trip at 5.3 seconds from a high pressurizer pressure signal. This reactor trip, along with the inherent reactor feedback mechanisms, rapidly reduces reactor power and heat generation which limits the pressure increase and prevents pressure from reaching the pressurizer safety valve setpoint of 2500 psia. If they had not been disabled for this scenario, the pressurizer PORVs would have opened to further limit the extent of the pressure transient. However, the 2436 psia (16.8 MPa) maximum pressure was still below the 2750 psia

TABLE C-14. SEQUENCE OF EVENTS FOR THE REACTOR COOLANT SYSTEM PRESSURE INCREASE BASELINE SCENARIO (NUMBER 1)

Time (s)	Event
0.0	Turbine tripped, turbine stop valve starts to close.
1.0	Turbine stop valve closed.
5.3	Reactor trip initiated on high pressurizer pressure.
7.5	Maximum primary system pressure reached, 16.8 MPa (2436 psia).
7.6	Main feedwater pumps trip on low discharge flow, motor driven auxiliary feedwater pumps start.
13.5	Steamline safety valves open.
15.0	Pressurizer heaters are turned on, low pressurizer pressure. setpoint reached.
30.0	Calculation stopped.

selection criteria (110 percent of design pressure), and below the 2545 psia that was reached in the H. B. Robinson FSAR limiting abnormal operational transient.

The results of the analysis for this baseline scenario closely follow the FSAR analysis results and are less severe than the FSAR analysis results. Therefore, the baseline scenario analysis is bounded by the FSAR analysis.

C.2.2 Reactor Coolant System Pressure Increase Scenario Number 2

The second step in the event scenario development process is to determine if any nonsafety grade systems were used to mitigate the baseline scenario, and if any nonsafety grade systems were used, to postulate their failure and deterministically analyze the resultant sequence. There were no nonsafety grade systems used to mitigate the baseline scenario. All of the nonsafety grade systems that would normally function to mitigate this transient were postulated to fail to operate. These failures include: pressurizer PORVs, steam dump system, pressurizer spray system, steamline PORVs, and the reactor trip from turbine trip. Had these systems (any or all of them) functioned as designed, this transient would have been less severe than analyzed.

C.2.3 Reactor Coolant System Pressure Increase Scenario Number 3

The third step in the event scenario development process is to examine the Reactor Coolant System Pressure Increase Baseline Scenario (Number 1) to determine if a single safety grade system failure was assumed. The safety grade system failure assumed was that one pressurizer safety valve was disabled so it could not open to relieve RCS pressure if required to do so.

The selected suspect systems list for reactor vessel pressure increase event was reviewed for the purpose of identifying safety grade system failures that would contribute to a reactor coolant system pressure

increase event. Table C-15 shows the selected suspect systems for a reactor coolant system pressure increase event. Of the systems listed, four are safety grade systems: the high head safety injection system, the RHR system [in its low pressure safety injection (LPSI) mode], the accumulator tank system, and the MSIVs.

The shutoff heads for the high head safety injection and RHR pumps are approximately 1500 psi and 150 psi, respectively which is far below the 2750 psia selection criterion pressure that is in effect while at normal plant operating temperatures. The accumulators are maintained at a nominal operating pressure of 660 psig and their relief valves are set at 700 psig (these relief valves would limit the accumulator pressure in case of a nitrogen regulator failure) which would preclude the possibility of the accumulators increasing RCS pressure above 700 psig. These emergency core cooling system (ECCS) components cannot aggravate a pressure increase scenario at operating temperatures, however, when the RCS temperature is reduced to the point where the corresponding 10 CFR 50 Appendix G[5] curve pressure limits are below the pressure where an ECCS subsystem can inject coolant into the RCS, then that system could contribute to an increase pressure event whenever the RCS is at or below that temperature.

The RHR system cannot cause a pressure increase event since the 150 psi shutoff head is below the 80°F pressure limit of ~440 psig from the pressure/temperature curve in the H. B. Robinson Technical Specifications. The RHR system should not be able to aggravate a pressure increase event by filling the pressurizer, for the pressurizer should be water solid whenever the RCS pressure is below 150 psi. Also, the RHR system should be aligned for the RHR recirculation mode when the RCS pressure decreases below 375 psig and temperature is below 350°F during plant cooldown.

The accumulator system and the high head safety injection system can cause or aggravate a pressure increase event at reduced RCS temperatures. An analysis of an inadvertent high head safety injection initiation at a low RCS temperature is included in Chapter 15 (Section 15.5) of the H. B. Robinson FSAR. A computer analysis of a scenario that involved

TABLE C-15. SELECTED SUSPECT SYSTEMS FOR A REACTOR COOLANT SYSTEM PRESSURE INCREASE EVENT

System	Failure Mode	Loss of Electrical Power or Air	Safety Grade	Postulated Effects
Reactor coolant system and pumps	No flow	1	No	A decrease reactor coolant system flow could contribute to an increase pressure transient since a decrease in flow causes a reduction in heat transfer from the primary which causes pressure to increase.
High head safety injection	Inadvertent start		Yes	An inadvertent start of the high head safety injection system could contribute to an increase pressure transient by filling the reactor coolant system liquid full.
Residual heat removal system	Inadvertent start		Yes	An inadvertent start of the RHR could contribute to an increase pressure transient by filling the system liquid full.
	No flow	1, 2		A no flow condition in the RHR system could contribute to an increase pressure transient by causing a gradual heatup and pressurization of the reactor coolant system.
Chemical and volume control system	High makeup or low letdown flow	1, 2	No	A high makeup or low letdown flow rate could contribute to an increasing reactor coolant system pressure transient by causing more water to be added than is being removed which could cause the system to go liquid full and pressure to increase.
Pressurizer pressure control system	Controlling pressure high	2	No	The pressurizer pressure control system could contribute to an increasing reactor coolant system pressure transient by controlling pressure high.
Accumulator tank system	Inadvertent injection		Yes	An inadvertent accumulator injection could contribute to an increase in reactor coolant system pressure by filling the system liquid full which could cause pressure to increase.
Control rod drive system	Rod withdrawal or ejection		No	An inadvertent rod withdrawal or ejection could contribute to an increasing reactor coolant system pressure transient by causing reactor power to increase which could cause pressure to increase.

TABLE C-15. (continued)

System	Failure Mode	Loss of Electrical Power or Air	Safety Grade	Postulated Effects
Feedwater and condensate system	No flow	1, 2	No	A low flow could contribute to an increase pressure transient by causing a reduction in heat transfer from the reactor coolant system.
Main steam system	Inadvertent MSIV closure	1	Yes	A low flow could contribute to an increase pressure transient by causing a reduction in heat transfer from the reactor coolant system.
Steam generator	Fails to transfer heat		No	A failure to transfer heat from the reactor coolant system could cause pressure to increase.
Turbine generator system	Inadvertent turbine control valve trip	1	No	An inadvertent turbine trip could contribute to an increase pressure transient by reducing the heat transfer from the reactor coolant system.
Auxiliary steam system	No flow		No	A loss of auxiliary steam could contribute to an increase pressure transient by causing a loss of condenser vacuum which reduces heat transfer from the reactor coolant system.
Main condenser, evacuation and circulating water systems	No circulating water flow or vacuum	1	No	A decreased circulating water flow or condenser vacuum could contribute to an increase pressure transient by reducing the heat transfer from the reactor coolant system.
Steam dump system	Fails to operate	1, 2	No	Steam dump failure to operate could contribute to an increase pressure transient by reducing the heat transfer from the reactor coolant system.

a. Loss of Electrical Power--1, Loss of Air--2.

failure modes that resulted in injection by both the accumulators and the high head safety injection pumps, was performed for this evaluation and is discussed in Section 2.5 of this report.

The remaining safety grade components are the MSIVs. Inadvertent closure of an MSIV would be bounded by the turbine trip with failure of the steam dumps. Inadvertent closure of more than one MSIV is beyond the scope of this study, for it would involve multiple failures of safety grade equipment.

C.2.4 Reactor Coolant System Pressure Increase Scenario Number 4

The fourth step in the event scenario development process is to establish whether or not the worst case initial plant conditions were used in the H. B. Robinson FSAR for a reactor coolant system pressure increase event.

The H. B. Robinson FSAR analysis of an instantaneous loss of load on the NSSS assumed an initial power of 102% of rated power. This reactor power level is higher than powers at which the plant would normally operate and would, therefore, be conservative for an increase in pressure transient due to loss of load. The initial pressure assumed for the FSAR analysis was 2280 psia, which is 30 psi above the nominal value. This pressure is a conservative value for an increase in pressure event and the operators would be alerted by an alarm if the pressure increased above this value. These initial plant parameters coupled with the equipment failures described above, are the worst case initial plant conditions for the turbine trip with loss of steam dump described in the FSAR.

The above conditions are considered worst case during plant operation, however, an increase in RCS pressure can be a problem in other plant modes. Due to brittle fracture considerations, the maximum allowable reactor coolant system pressure decreases as the temperature decreases. These reduced pressure limits are defined by the Technical Specification heatup and cooldown curves (per 10 CFR 50 Appendix G). It was found that an increase in RCS pressure can be a problem when the reactor is shutdown at low temperatures and pressures. Two sequences that were analyzed

starting at these low-temperature and low pressure initial conditions, produced results that exceeded the pressure limits for the postulated initial RCS temperatures. These analyses and their results are discussed in Section 2.5 as Reactor Coolant System Pressure Increase Sequences 1 and 2.

C.2.5 Reactor Coolant System Pressure Increase Scenario Number 5

The purpose of this step is to identify system failures from the selected suspect system list (Table C-15) that would have the greatest effect in aggravating the baseline scenario, or in other words, produce the worst case scenario in an attempt to exceed Selection Criterion 2.

For this event the failure mode of concern for the reactor coolant system and pumps is a loss of flow, which would result in a decrease in heat transfer to the secondary. To analyze this system failure a scenario was evaluated on the computer that considered a loss of AC power and loss of letdown flow in conjunction with the failures assumed for the baseline scenario. A loss of AC power would also result in the additional aggravators of loss of feedwater and condensate flow and loss of condenser vacuum. The results of this transient are less severe than the results of the baseline scenario since the loss of reactor coolant pumps causes an immediate reactor trip which reduces the heat input from the reactor. The net effect of these interactions is a decrease in RCS pressure instead of the pressure spike seen in the baseline scenario results. A sequence of events for the Reactor Coolant System Pressure Increase Scenario Number 5 is provided in Table C-16.

C.2.5.1 Reactor Coolant System Pressure Increase Scenario Number 5a. An examination of the suspect aggravating system list showed that a failure of the control rod drive system could cause an increase in reactor power which would cause RCS pressure to increase. Reactor Coolant System Pressure Increase Scenario Number 5a evaluates the baseline scenario aggravated by a continuous rod withdrawal and maximum charging flow by the chemical and volume control system (CVCS).

TABLE C-16. SEQUENCE OF EVENTS FOR REACTOR COOLANT SYSTEM PRESSURE INCREASE SCENARIO NUMBER 5

Time (s)	Event
0	Reactor at 102% full power, RCS pressure is 2280 psia, all controls are in automatic.
1.0	The turbine trips and the steam dumps fail to open. Reactor coolant pumps begin coast down, the reactor trips from loss of RCPs, main feedwater pumps stop, and the condenser evacuation pumps and circulating water pumps are deenergized. Letdown flow is isolated. Turbine stop valves start to close.
2.0	The turbine stop valves are closed.
4.5	Low pressurizer pressure setpoint reached.

This scenario resulted in a maximum RCS pressure of 2428 psia. The transient was mitigated by a reactor trip that was actuated by a high pressurizer pressure. The response for this transient was almost identical to the baseline scenario results. The continuous rod withdrawal resulted in a 5 MW increase in core thermal power which is almost negligible in its effect on the transient. Even at the maximum withdrawal speed of 72 steps per minute, the reactivity addition rate is slow enough that this failure mode does not make any significant contribution. The CVCS failure results in reaching the high pressure reactor trip at 5.1 seconds versus 5.3 seconds for the baseline scenario, which results in a decrease of 8 psi in the peak pressure. A sequence of events for Reactor Coolant System Pressure Increase Scenario Number 5a is provided in Table C-17.

C.2.5.2 Reactor Coolant System Pressure Increase Scenario Number 5b. Reactor Coolant System Pressure Increase Scenario Number 5 evaluated a loss of letdown flow and the Reactor Coolant System Pressure Increase Scenario Number 5a analyzed a maximum charging pump flow into the RCS. In both cases the CVCS failure had little effect on the transient results due to the dampening effect of the pressurizer vapor volume. To adequately evaluate the effects of a charging flow/letdown flow mismatch, a scenario was considered with the RCS water solid. Taking the plant water solid during power operation is a procedural violation and is, therefore, beyond the scope of this study. However, when the plant is in a cold shutdown condition, it is taken water solid and a charging flow/letdown flow mismatch can result in an increase in RCS pressure.

Reactor Coolant System Pressure Increase Scenario Number 5b was initiated at 100°F, 350 psia, with the RHR in the cooldown mode, and all reactor coolant pumps (RCPs) off. The letdown valve was failed closed with a charging pump operating at maximum speed in manual control. One of the pressurizer PORVs was assumed to fail to open, but the remaining PORV did mitigate the event by opening whenever the setpoint was exceeded. The maximum pressure reached during this transient was 416 psia which is below the pressure limit of ~440 psia at 100°F. The sequence of events for this scenario is presented in Table C-18.

TABLE C-17. SEQUENCE OF EVENTS FOR REACTOR COOLANT SYSTEM PRESSURE INCREASE SCENARIO NUMBER 5a

Time (s)	Event
0.0	Turbine tripped, turbine stop valve starts to close, rod cluster control assembly (RCCA) begins to withdraw, and makeup flow increases to maximum.
1.0	Turbine stop valve closed.
5.1	Reactor trip initiated on high pressurizer pressure.
6.7	Maximum pressurizer pressure reached (2428 psia).

TABLE C-18. SEQUENCE OF EVENTS FOR REACTOR COOLANT SYSTEM PRESSURE INCREASE SCENARIO NUMBER 5b

Time (s)	Event
0.0	Reactor shutdown, the RCS is water solid at 100°F and 350 psia. RHR is operating in the cooldown mode. All RCPs are off. One charging pump is operating in manual.
1.0	The letdown valve closes due to a failure.
11.7	Pressurizer PORV-B opens.
12.9	PORV-B closes.
15.7	PORV-B opens.
16.9	PORV-B closes.
19.7	PORV-B opens.
20.9	PORV-B closes.
23.7	PORV-B opens.
24.9	PORV-B closes.
25.0	Calculation was terminated.

C.2.5.3 Reactor Coolant System Pressure Increase Scenario Number 5c. Most of the suspect systems are not in operation or are disabled to prevent their operation during cold shutdown conditions and as such cannot cause or aggravate increase in pressure transients while the plant is in this mode (i.e., all secondary systems are off and the high head safety injection and the accumulator systems are disabled by procedure). One failure mode that was evaluated during cold shutdown was an RCP start with a 50°F ΔT between the steam generator (200°F) and the reactor (150°F).

This scenario was initiated with the RCS water solid at 150°F and 300 psia with all three RCPs off. RCP-C is inadvertently started which results in a heat-up of RCS coolant as it circulates through the hotter steam generators. The heat-up results in a pressure increase which is mitigated by one of the pressurizer PORVs (the other PORV is assumed to fail to operate). A sequence of events for this scenario is presented in Table C-19. The justifications for not performing further computer analyses on suspect system failures is given in Table C-20.

C.2.6 Systems Susceptible to Loss of Electrical Power or Loss of Air

The final step in the event scenario devel pment process is to analyze those systems dependent on electrical power or air. There are several systems that, upon a loss of electrical power, transfer to their failure mode of concern as identified in Table C-15. Reactor Coolant System Pressure Increase Scenario Number 5 assumed a loss of AC power and the analysis indicated that this loss of power did not aggravate the transient, but lead to its rapid mitigation by resulting in a reactor trip from loss of RCPs. During low temperature conditions a loss of electrical power could cause a letdown isolation and loss of RHR flow. The loss of letdown was analyzed in Reactor Coolant System Pressure Increase Scenario Number 5b and Reactor Coolant System Pressure Increase Sequence Number 1 from Section 2.5. The RHR pumps perform a safety function in the LPSI mode and their power supplies meet safety grade standards. Therefore, a loss of power to both RHR pumps is beyond the scope of this study.

TABLE C-19. SEQUENCE OF EVENTS FOR REACTOR COOLANT SYSTEM PRESSURE INCREASE SCENARIO NUMBER 5c

Time (s)	Event
0.0	Transient initiated by starting RCP-C.
1.0	RCP-C reached full speed of 1241.5 RPM.
5.2	PORV lift setpoint pressure of 414.7 psia reached.
5.8	PORV began opening.
6.15	Maximum pressurizer pressure reached - 428.2 psia.
7.2	PORV began closing, maximum area = 48% open maximum flow rate = 115.30 lbm/s.
7.9	PORV closed.
8.9	PORV lift setpoint pressure of 414.7 psia reached.
9.5	PORV began opening.
9.8	Maximum pressurizer pressure reached - 424.8 psia.
10.75	PORV began closing, maximum area = 40% open maximum flow rate = 103.52 lbm/s.
11.4	PORV closed.
12.5	PORV lift setpoint pressure of 414.7 psia reached.
13.1	PORV began opening.
13.4	Maximum pressurizer pressure reached - 423.1 psia.
14.35	PORV began closing, maximum area = 40% open maximum flow rate = 103.38 lbm/s.
15.0	PORV closed.
16.05	PORV lift setpoint pressure of 414.7 psia reached.
16.65	PORV began opening.
16.95	Maximum pressurizer pressure reached - 424.9 psia.

TABLE C-19. (continued)

Time (s)	Event
17.95	PORV began closing, maximum area = 42.5% open maximum flow rate = 107.37 lbm/s.
18.65	PORV closed.
20.0	Calculation stopped. Reactor vessel downcomer temperature 168.5°F.

TABLE C-20. JUSTIFICATIONS FOR NOT UTILIZING AGGRAVATING SYSTEMS IN ADDITIONAL PRESSURE INCREASE COMPUTER ANALYSES

Suspect Aggravating System	Failure Mode	Justification
Reactor coolant system and pumps	No flow	See Reactor Coolant System Pressure Increase Scenario Number 5 (Section C.2.5).
High head safety injection system	Inadvertent start	The 1500 psi shutoff head of the HPSI pumps is not sufficient to exceed the operating temperature pressure limit of 2750 psia. For low temperature operation see Reactor Coolant System Overpressure Sequence Number 2 (Section 2.5.4).
Residual heat removal system	Inadvertent start	The 150 psi shutoff head of the RHR pumps is not sufficient to exceed the operating temperature pressure limit of 2750 psia or the low temperature limits as established in the H. B. Robinson Technical Specifications.
	No flow	As required by 10 CFR 50 General Design Criteria 34, a means is available at H. B. Robinson, Unit 2 to remove decay heat, given the most limiting single failure in the RHR system, utilizing safety grade equipment.
Chemical and volume control system	High makeup or low letdown flow	For operating temperatures, see Reactor Coolant System Pressure Increase Scenarios Numbers 5 and 5A (Sections C.2.5 and C.2.5.1). For low temperature conditions, see Reactor Coolant System Pressure Increase Scenario Number 5B (Section C.2.5.2) and Reactor Coolant System Overpressure Sequence Number 1 (Section 2.5.3).
Pressurizer pressure control system	Pressure controlling high	See Reactor Coolant System Pressure Increase Scenarios Number 1, 5, and 5A (Sections C.2.1, C.2.5, and C.2.5.1) where the initial pressure was assumed to be 2280 psia, 30 psi above nominal.
Accumulator tank system	Inadvertent injection	The 700 psig accumulator relief valve setpoint does not permit accumulator pressures sufficient to exceed the operating temperature pressure limit of 2750 psia. Inadvertent injection would involve a procedural violation during most shutdown conditions. See Reactor Coolant System Overpressure Sequence Number 2 (Section 2.5.4).

TABLE C-20. (continued)

Suspect Aggravating System	Failure Mode	Justification
Control rod drive system	Rod withdrawal or ejection	For rod withdrawal see Reactor Coolant System Pressure Increase Scenario Number 5A (Section C.2.5.1). For a rod ejection, this event results in a LOCA as well as a positive reactivity addition and is analyzed as an increase in positive reactivity. As a LOCA, this event is bounded by the FSAR DBA LOCA analysis.
Feedwater and condensate system	No flow	See Reactor Coolant System Pressure Increase Scenario Number 5 (Section C.2.5).
Main steam system	Inadvertent MSIV closure	Closure of one MSIV is bounded by the turbine trip with coincident failure of the Steam Dump System. Closure of more than one MSIV requires multiple safety grade failures which is beyond the scope of this analysis.
Steam generator	Fails to transfer heat	There is no known catastropic failure mechanism for this failure mode. A loss of heat transfer capability in the steam generator is a slow process that would extend over a sufficiently long time period to allow detection and correction.
Turbine generator system	Inadvertent turbine trip	See Reactor Coolant System Pressure Increase Scenarios Number 1, 5, and 5A (Sections C.2.1, C.2.5, and C.2.5.1).
Auxiliary steam system	No flow	This failure mode could result in a loss of condenser vacuum which is analyzed in Reactor Coolant System Pressure Increase Scenario Number 5 (Section C.2.5).
Main condenser, evacuation, and circulating water systems	No vacuum or loss of circulating water flow	See Reactor Coolant System Pressure Increase Scenario Number 5 (Section C.2.5).
Steam dump system	Fails to operate	See Reactor Coolant System Pressure Increase Scenarios Number 1, 5, and 5A (Sections C.2.1, C.2.5, and C.2.5.1).

A loss of air affects the CVCS, the pressurizer pressure control system, the feedwater and condensate system, and the steam dump system. Loss of air to the CVCS would cause a letdown isolation which was analyzed in Reactor Coolant System Pressure Increase Scenario Number 5b and Reactor Coolant System Pressure Increase Sequence Number 1 from Section 2.5. Loss of air to the pressurizer pressure control and steam dump would result in a loss of pressurizer spray flow and the ability of the steam dump to operate. Both of these failures were assumed in Reactor Coolant System Pressure Increase Scenarios Number 1, 5, and 5a and have, therefore, been analyzed. Loss of air would have the same effect on feedwater and condensate as loss of power which was analyzed in Reactor Coolant System Pressure Increase Scenario Number 5.

C.2.7 Summary of Reactor Coolant System Pressure Increase Scenarios

The analysis of a complete loss of steam load on the NSSS found in the H. B. Robinson FSAR bounds the effects of an increase in RCS pressure for operating plant conditions. This is based on the conservative assumptions used in the FSAR analysis and on a comparison of the results of that analysis and the analyses conducted as part of this study. These results show that no suspect system failure or combination of suspect system failures can aggravate the baseline scenario sufficiently to make the transients more severe than the transient presented in Chapter 15 of the H. B. Robinson FSAR.

For low temperature conditions, there are two scenarios that were found to exceed the Technical Specification temperature-pressure curve. These analyses are discussed under Reactor Coolant System Pressure Increase Sequence Number 1 and 2 in Section 2.5 of this report.

C.3 Positive Reactivity Addition Scenarios

The next events of concern are positive reactivity addition events. The concerns related to a positive reactivity addition event for this analysis are failures that cause an inadvertent positive reactivity addition which results in a reactor power increase and a threat to core integrity. The system failures assumed for this evaluation were analyzed in an attempt to cause DNBR to decrease below 1.30.

In Chapter 15 of the H. B. Robinson Unit 2 FSAR, the limiting transient and the DBA for a positive reactivity addition event are presented. Respectively, they are an uncontrolled rod cluster control assembly (RCCA) withdrawal at power and a rod cluster control assembly ejection. The following scenario development and deterministic analysis process begins with a discussion of the uncontrolled RCCA withdrawal at power transient and the RCCA ejection DBA as presented in Chapter 15 of the H. B. Robinson Unit 2 FSAR.

The positive reactivity addition limiting transient presented in Chapter 15 of the H. B. Robinson Unit 2 FSAR is an uncontrolled RCCA withdrawal at power. An controlled RCCA withdrawal at a core power of 2346 Mwt results in an increase in core heat flux. Since the heat extraction from the steam generator remains constant, there is a net increase in reactor coolant temperature. Unless terminated by manual or automatic action, this power mismatch and resultant coolant temperature rise would eventually result in DNB. Therefore, to prevent the possibility of damage to the cladding, the reactor protection system (RPS) is designed to terminate any such transient with an adequate margin to DNB.

The automatic features of the RPS which prevent core damage in a rod withdrawal accident at power include the following:

1. Nuclear power range instrumentation actuates a reactor trip if two out of the four channels exceed an overpower setpoint.

2. Reactor trip is actuated if any two out of three ΔT channels exceed an overtemperature ΔT setpoint. This setpoint is automatically varied with power distribution, temperature and pressure to protect against DNB.

3. Reactor trip is actuated if any two out of three ΔT channels exceed an overpower ΔT setpoint. This setpoint is automatically varied with power distribution to ensure that the allowable fuel power rating is not exceeded.

4. A high pressure reactor trip, actuated from any two out of three pressure channels, is set at a fixed point. This set pressure will be less than the set pressure for the pressurizer safety valves.

The purpose of the H. B. Robinson Unit 2 FSAR analysis is to demonstrate the manner in which the above protective systems function for various reactivity insertion rates from different initial conditions. Reactivity coefficients, initial conditions and effects of control functions govern which protective function occurs first.

The H. B. Robinson Unit 2 FSAR analysis is performed using several digital computer codes. First, the actual core limits are determined employing a DNB correlation. Protection lines are then selected and incorporated into a transient analysis by a detailed digital simulation of the unit.

In the analysis, the effect of the RCCA movement on core power distribution is considered by its effect of causing a decrease in overtemperature ΔT and overpower ΔT trip setpoints proportionate to the decrease in margin to DNB. This has the effect of causing a reactor trip sooner in the transient.

Principal assumptions in the H. B. Robinson Unit 2 FSAR analyses are:

1. Overtemperature ΔT trip setpoints are as discussed. The nuclear overpower setpoints will be 118% of 2300 Mwt including maximum errors.

2. Initial (steady-state) conditions are:

Case	Core Power	T_{avg}, °F	Pressure, psia
a	102%	597.4	2220
b	62%	568.1	2220
c	12%	553.85	2220

3. Both high and low reactivity feedback cases were examined. A zero moderator density coefficient was used for the minimum feedback case and 0.43 Δ/gm/cc for the maximum feedback case. Low and high Doppler defects were assumed for the respective cases.

4. The reactivity insertion was assumed to continue until terminated by trip without regard to the limited reactivity worth of control rods inserted in the core.

It was shown that two reactor trip channels provide cover over the whole range of reactivity rates; these are high neutron flux and overtemperature ΔT trip channels. It was also shown that the minimum DNBR is greater than 1.30.

For rod withdrawal accidents starting at 60% power, reactor trip occurs because of the activation of one of two different trip channels, namely overtemperature ΔT and high neutron flux. It was shown that the high ΔT overtemperature trip extends to about 10^{-4} δk/s. For high reactivity rates, greater than 2×10^{-4} δk/s, trip occurs from high neutron flux. The minimum DNBR for the range of reactivity rates is greater than 1.30.

The results for rod withdrawal accidents starting at 10% power are very similar to the 60% power case. The minimum value of DNBR for all reactivity rates is greater than 1.30.

In the unlikely event of a control rod withdrawal incident, from full power operation or lower power levels, the core and RCS are not adversely affected since the minimum value of DNBR reached is in excess of 1.30 for all rod reactivity rates. Protection is provided by neutron flux overpower and overtemperature ΔT.

An uncontrolled RCCA bank withdrawal at power conditions was performed for an Exxon fueled core to demonstrate that no reduction in safety margin occurs. Plant responses were analyzed at beginning of life (BOL) for a rapid withdrawal rate of 5.625×10^{-4} $\delta k/s$ at full power, and at 62% power with a withdrawal rate of 4.0×10^{-4} $\delta k/s$, which would result in the minimum mean departure from nucleate boiling ratio (MDNBR). The MDNBR for both cases remained above 1.7.

The effect of a positive moderator temperature reactivity feedback coefficient as compared to a zero or negative value is a faster reactor power increase resulting from the control rod withdrawal. Thus, the effect of a more positive moderator coefficient can be pictured as being equivalent to selecting a higher withdrawal rate. The identical reactor trip setpoint as before will be reached, the high neutron flux trip for the fast withdrawal, the overtemperature ΔT trip for the slow withdrawal. However, the rate of the power increase and the resulting rate of heat flux increase at the time of the trip may be higher for the more positive coefficient, and therefore, a slight decrease in thermal margin may occur, caused by a higher overshoot of the trip variable over the trip setpoint. On the other hand, if the accelerated power increase is sufficiently fast compared to the thermal response time, the trip may occur early enough to eliminate the major part of the heatup occurring in the original transient and thereby improve the minimum thermal margin. As a result, approximately the same MDNBR is anticipated for both + 2.0 pcm/F and 0.0 pcm/F moderator temperature coefficients.

Two cases were analyzed to cover the full range of reactivity insertion rate:

1. Fast rod withdrawal, and

2. Slow rod withdrawal.

The fast control rod withdrawal used a reactivity insertion rate of 5.625×10^{-4} $\Delta\rho$/s. Rod withdrawal cases with both a 1.2 and 0.8 multiplier applied to the Doppler coefficient have been analyzed with the 1.2 multiplier case showing a slightly lower MDNBR. A 1.25 multiplier was applied to the moderator temperature coefficient to augment the effect of the positive reactivity feedback. The reactor scrammed (start of rod insertion) on high neutron flux signal at about 2.0 s after the initiation of the transient. The MDNBR of the transient was 2.12.

The slow control rod withdrawal used a reactivity insertion rate of 2.5×10^{-5} $\Delta\rho$/s. A 0.8 multiplier was applied to the Doppler coefficient to reduce its negative reactivity feedback. A 1.25 multiplier was applied to the moderator temperature coefficient. The reactor scrammed at about 40 s on overtemperature ΔT signal. A 6 s trip delay time was included in the analysis for conservatism. The MDNBR was 1.96.

For the part load case, the original analysis has shown the same trip functions protect the core and approximately the same MDNBR is reached. Since the effect of the more positive moderator temperature coefficient (MTC) has been demonstrated to be insignificant for this transient and a better margin to DNB exists in the current analysis, it is not considered necessary to reanalyze the part load case of this event.

The sequence of events for the uncontrolled RCCA withdrawal at power limiting transient from the H. B. Robinson Unit 2 FSAR is presented in Table C-21.

The positive reactivity addition DBA presented in Chapter 15 of the H. B. Robinson Unit 2 FSAR is a RCCA ejection. This accident is defined as the mechanical failure of a control rod mechanism pressure housing,

TABLE C-21. H. B. ROBINSON FSAR SEQUENCE OF EVENTS FOR AN UNCONTROLLED RCCA BANK WITHDRAWAL AT POWER

Time (s)	Event
0	Reactor operating at 2346 Mwt Rod withdrawal occurs.
2.0	Reactor scram on high neutron level for fast rod withdrawal. MDNBR reached was 2.12.
40	Reactor scram on overtemperature ΔT trip for slow rod withdrawal. MDNBR reached was 1.96.

resulting in the ejection of a RCCA and drive shaft. The consequence of this mechanical failure is a rapid reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage.

In order for this accident to occur, a rupture of the control rod mechanism housing must be postulated creating a full system pressure differential acting on the drive shaft. The resultant core thermal power excursion is limited by the Doppler reactivity effect of the increased fuel temperature and terminated by reactor trip actuated by high nuclear power signals.

The operation of a chemical shim plant is such that the severity of an ejection accident is inherently limited. Since control rod clusters are used to control load variations only and core depletion is followed with boron dilution, only a few rods in the core are at full power. There are low and low-low level insertion monitors, each with both visual and audio signals. Operating instructions require boration at the low level alarm and emergency boration at the low-low alarm. For all cases, utilizing the flexibility in being able to select the control rod cluster groupings, radial locations, and positions as a function of load, the design minimizes the peak fuel and clad temperatures. It is shown that in no case does clad melting occur.

If a rod ejection accident were to occur, a fuel rod thermal transient which could cause DNB, may occur together with limited fuel damage. The amount of fuel damage that can result from such an accident will be governed mainly by the worth of the ejected rod and power distribution attained with the remaining control rod pattern. Certain design features, as well as administrative rules on plant operability, limit the reactivity holding of control rod banks. When this is combined with a reactor trip from the redundant nuclear overpower protection, the possible consequences of a rod ejection accident are safely limited.

The real physical limits of this accident are that the rod ejection accident ard any consequential damage to either the core or the RCS must not prevent long-term core cooling and that any offsite dose consequences must be within the guidelines of 10 CFR 100[6]. More specific (and restrictive) criteria are applied to assure that fuel dispersal in the coolant, gross lattice distortion, or severe shock waves will not occur. These criteria are:

1. Average fuel pellet enthalpy at the hotspot below 225 cal/gm for nonirradiated fuel and 200 cal/gm for irradiated fuel.

2. Average clad temperature at the hotspot below 2700°F, the temperature above which clad embrittlement may be expected.

3. Peak reactor coolant pressure less than that which would cause stresses to exceed the faulted condition stress limits.

4. Fuel melting limited to less than the innermost 10% of the fuel pellet at the hotspot, even if the average fuel pellet enthalpy at the hotspot is below the limits of criterion (1).

The ejected rod worths and hot pellet peaking factors, before and after the ejection of the rod, were calculated using the PDQ-7 code[7]. No credit was taken for the power flattening effects of Doppler or moderator feedback in the calculation of rejected rod worths or peaking factors.

The nuclear power transient was calculated with the XTRAN code[8] at the beginning and end of the fuel cycle for full and zero power. Conservative Doppler and moderator feedback values were used in all of these calculations. The ejected rod worths in the XTRAN calculations were equal to or greater than those calculated by PDQ-7. The hotspot factors calculated with XTRAN, with thermal and hydraulic feedback, were also forced to agree with those calculated by PDQ-7. The rod was removed from the core by accelerating it from an initially fully inserted position at the rate of 2400 ft/s^2, causing the rod to be completely removed from the core in 0.1 s.

The scram bank was assumed to begin entry into the core at 0.5 s after the initiation of the rod ejection. This delay is constituted of 0.2 s for the instrumentation to produce a signal, 0.15 s for the trip breaker to open and 0.15 s for coil release. The rods were assumed to enter the core at the rate of 6.67 ft/s, which corresponds to the Technical Specification limit of 1.8 s for complete insertion of the slowest moving control rod. A conservative scram bank worth of less than 4.0% ΔK was assumed for all reactor conditions. This compares with calculated shutdown worths of 5.62 and 5.83% $\Delta\rho$ at the beginning and end of cycle, respectively. These calculated worths account for the most reactive rod being stuck out and were further reduced by 10% to reflect calculational uncertainties.

At beginning of life (BOL), full power conditions, the rod program will limit the control bank worth to significantly less than one full control bank; however, the maximum worth rod (0.376% ΔK) was conservatively determined by assuming the D bank to be fully inserted. The peak reactor power during the transient is 2.58 times the assumed initial power condition of 2346 Mwt. The resulting peak inside clad and center line fuel temperatures calculated by XTHETA[9] are 930°F and 4130°F, respectively.

For the BOL hot zero power condition there was assumed to be two control banks fully inserted. The worst ejected rod worth of 0.56% ΔK results in a power increase of only approximately 100 times the initial condition. Since this value is far below rated power conditions, no further calculations were made for this case.

For the end of life (EOL), full power condition, as in the BOL full power case, the worth of the worst ejected rod (0.39% ΔK) was again determined from one fully inserted control bank condition. The peak power reached for an ejected rod worth of 0.40% ΔK is 3.61 times the initial power condition of 2346 Mwt. Even though the rod worth is approximately the same as that as BOL, this reactivity addition brings the core at EOL much closer to prompt critical, which results in a significantly higher power increase. The resulting peak inside clad and center line fuel temperature are 990°F and 4200°F, respectively.

For the EOL zero power condition, there was assumed to be two control banks fully inserted with only one main coolant pump operating. For the case of the reactor being at 0.1% of rated power initially, the peak power attained by the core was 86% of rated power for an ejected rod worth 0.55% ΔK. The peak center line fuel temperature as calculated by XTRAN using conservative heat transfer coefficients was only 844°F; therefore, no additional calculations were made for this case.

Additional calculations were made to assure that the results presented are indeed conservative. The XTRAN calculations described thus far utilized a very effective (536 Btu/hr-ft^2) heat transfer coefficient between fuel and coolant. This causes the amount of feedback due to moderator changes to be conservative, particularly for end of cycle (EOC) conditions when the moderator coefficient is strongly negative. It was not clear, however, that the Doppler feedback was not being overestimated due to an unrealistically rapid rise in fuel temperature. XTRAN was rerun using the same ejected rod worth and peaking factors, but with a much larger (3330 Btu/hr-ft^2) effective heat transfer coefficient for the beginning of cycle, full power condition. The result was the transfer coefficients. With high heat transfer coefficients, the fuel temperatures initially (and throughout the transient) were much lower than the reference case. This resulted in the heat capacity of the fuel being much smaller. It follows, then, that for a fixed amount of energy insertion into fuel at different initial temperatures, the temperature increase for the fuel at the lower temperature will be greater than for the fuel at a higher temperature. The result was that for higher heat transfer coefficients the fuel underwent a more rapid temperature increase and caused the reactor to shut down sooner; hence, it is conservative to use small heat transfer coefficient to calculate the core power.

The same effect as discus .ve was observed in XTHETA calculations of the beginning of cycle full power condition rod ejection when gap coefficient was reduced by a factor of two. The initial peak center line temperature was higher by about 250°F, but the peak temperature reached during the transient was higher by only 200°F.

The conclusion reached in Chapter 15 of the H. B. Robinson FSAR is that due to the relationship of fuel heat capacity with temperature, it is conservative to calculate the reactor power versus time using small heat transfer coefficients. It can also be concluded that it is conservative to calculate the fuel temperature increase during the transient with high heat transfer coefficients.

The peak fuel temperatures are far below the temperatures corresponding to fuel melting or contained enthalpy of 280 cal/gm. The peak clad temperatures are much less than the temperature at which the cladding integrity becomes questionable. The XTHETA calculational model used in the thermal analysis takes the exothermic zirconium-steam reaction into account using the Baker-Just parabolic rate equation, but the clad temperature never reached the point at which this reaction becomes significant.

The sequence of events for the RCCA ejection DBA from Chapter 15 of the H. B. Robinson Unit 2 FSAR is presented in Table C-22.

C.3.1 Positive Reactivity Addition Baseline Scenario (Number 1)

The first step in the positive reactivity addition scenario development process is to deterministically examine the effects of a failure resulting in a continuous rod withdrawal. The Positive Reactivity Addition Baseline Scenario (Number 1) is essentially the same scenario as the limiting transient presented in the H. B. Robinson Unit 2 FSAR with one exception. The analysis performed for the FSAR was conducted at three reactor power levels, 10%, 62%, and 102%. The H. B. Robinson Unit 2 FSAR demonstrated that DNBR varied with a change in power, however, the change was very small. Since the event outcome is not sensitive to the initial power level, 67% (1536 MW) power was assumed. By assuming 67% reactor power, a power level near the middle of the operating range was selected which is considered to be a realistic operating level and is close to one analyzed in the H. B. Robinson Unit 2 FSAR which provides for a comparison between the two.

TABLE C-22. H. B. ROBINSON FSAR SEQUENCE OF EVENTS FOR A RCCA EJECTION

Time (s)	Event
0	Reactor power is 2346 Mwt.
0.1	Rod completely removed from core.
0.5	Reactor scram initiation.
2.3	Rods completely in core.

The initial plant conditions for the Positive Reactivity Addition Baseline Scenario are reactor power at 67% and all control systems in automatic except rod control which is in manual. The initiating event is assumed to be a continuous RCCA withdrawal in the middle of the "D" Bank. As the rod assembly is extracted from the core, reactor power increases which causes an increase in reactor coolant temperature. Reactor power peaks at 1544.6 MW by 114 s with an increase of 8.6 MW. Reactor coolant temperature increases from 559.7 to 568.7°F for an increase of 9°F. The reactivity addition resultes in the plant operating at a higher steady state power level and reactor coolant temperature. Table C-23 presents the sequence of events for the Positive Reactivity Addition Baseline Scenario (Number 1).

The final results of the Positive Reactivity Addition Baseline Scenario (Number 1) differ from the results presented in the H. B. Robinson Unit 2 FSAR. The H. B. Robinson Unit 2 FSAR case ends with the increase in power causing a high neutron flux trip or a high ΔT overtemperature trip where the computer analysis performed for the Positive Reactivity Addition Baseline Scenario (Number 1) evaluation ended in a new steady state operation. These two analyses differ due to the conservative assumptions made in the H. B. Robinson Unit 2 FSAR evaluation computer model. The calculation performed for the Positive Reactivity Addition Baseline Scenario (Number 1) evaluation was less severe than the H. B. Robinson Unit 2 FSAR case. This conclusion was drawn on the basis that the power increase experienced during the Positive Reactivity Addition Baseline Scenario (Number 1) calculation was not as large as the power increase experienced in the H. B. Robinson Unit 2 FSAR analysis therefore the coolant temperature change was also not as large. Even though the power change was not as large as in the H. B. Robinson FSAR analysis, the Positive Reactivity Addition Baseline Scenario (Number 1) is considered to be indicative of actual plant reaction for this event.

TABLE C-23. SEQUENCE OF EVENTS FOR THE POSITIVE REACTIVITY ADDITION BASELINE SCENARIO (NUMBER 1)

Time (s)	Event
0.0	Reactor power at 67%. Rod control in manual. Transient initiated by withdrawing the middle RCCA of the 'D' Bank. Initial RCCA position was 174.54 steps inserted.
18.78	RCCA withdrawn from lower third of core.
50.45	RCCA withdrawn from lower half of core.
82.12	RCCA withdrawn from lower 2/3 of core.
113.78	RCCA withdrawn from lower 5/6 of core. Maximum core power achieved (1544.6 MW).
145.45	RCCA fully withdrawn from core.
150.0	Calculation stopped.

C.3.2 Positive Reactivity Addition Scenario Number 2

The second step in the event scenario development process is to determine if any nonsafety grade systems were used to mitigate the baseline scenario and if any nonsafety grade systems were used to mitigate the event, to postulate their failure and to deterministically analyze the effects. No nonsafety grade systems were used to mitigate a continuous rod withdrawal event.

C.3.3 Positive Reactivity Addition Scenario Number 3

The third step in the event scenario development process is to examine the baseline scenario to determine if a single safety grade system failure was assumed. No single safety grade system failures were assumed for the continuous rod withdrawal during reactor startup. The selected suspect systems list for a positive reactivity addition event was reviewed for the purpose of identifying safety grade failures that would contribute to a positive reactivity addition event. Of the systems listed as possible contributors, three are safety grade systems: steamline overpressure protection, main steam, and auxiliary feedwater. (See Table C-24.)

The safety grade failures are bounded by Steam Generator Overfill Scenario Number 5 presented in Section C.7.5. In the Steam Generator Overfill Scenario Number 5, the turbine control valves and steam dump valves are assumed to fail open in addition to a continuous rod withdrawal and a maximum feedwater flow to one steam generator. The steamline overpressure protection system is bounded by the failure of the steam dump system (SDS) as the SDS has approximately four times the steam flow capacity of the steamline overpressure protection system. Failure of the turbine control valves and SDS also bounds inadvertent opening of an MSIV due to the large steam flow capacity associated with the turbine control valves and SDS. The main feedwater system also has a significantly larger flow rate than does the auxiliary feedwater system. From the analysis for Steam Generator Overfill Scenario Number 5, reactivity was not

TABLE C-24. SELECTED SUSPECT SYSTEMS FOR POSITIVE REACTIVITY ADDITION EVENTS

System	Failure Mode	Loss of Electrical Power or Air	Safety Grade	Postulated Effects
Reactor coolant system and pumps	Inadvertent start		No	An inadvertent start of an idle pump could contribute to an increase positive reactivity transient by adding reactivity due to the cold water in the idle loop.
Chemical and volume control system	Adding nonborated water	1, 2	No	Adding nonborated water could contribute to an increase positive reactivity transient by adding reactivity due to the removal of boron from the reactor coolant system.
Control rod drive system	Inadvertent rod withdrawal or ejection		No	An inadvertent rod withdrawal or ejection could contribute to an increase positive reactivity transient by adding reactivity with rod movement.
Feedwater and condensate system	High flow or loss of heating	2	No	High flow or low feed water temperature could contribute to an increase positive reactivity transient as the increase heat transfer from the reactor coolant system adds positive reactivity.
Steamline overpressure protection system	Inadvertent PORV or safety valve opening		Yes	An inadvertent valve opening could contribute to an increase positive reactivity transient by increasing the heat transfer from the reactor coolant system which adds positive reactivity.
Main steam system	Inadvertent MSIV opening		Yes	An inadvertent valve opening could contribute to an increase positive reactivity transient by increasing the heat transfer from the reactor coolant system which adds positive reactivity.
Turbine generator system	Inadvertent turbine control valve opening		No	An inadvertent valve opening could contribute to an increase positive reactivity transient by increasing the heat transfer from the reactor coolant system which adds positive reactivity.

TABLE C-24. (continued)

System	Failure Mode	Loss of Electrical Power or Air	Safety Grade	Postulated Effects
Auxiliary feedwater system	Inadvertent start	1	Yes	Inadvertent system start could contribute to an increase positive reactivity transient by adding cold water to the steam generator which increases heat transfer from the reactor coolant system and adds positive reactivity.
Steam generator blowdown system	High flow		No	A high flow could contribute to an increase positive reactivity transient by requiring the coolant removed to be replaced by cooler water which increases the heat transfer from the reactor coolant system and adds positive reactivity.
Auxiliary steam system	High flow		No	A high flow could contribute to an increase positive reactivity transient by increasing the heat transfer from the reactor coolant system which adds positive reactivity.
Main condenser, evacuation and circulating water systems	High circulating water flow or increased vacuum		No	A high circulating water flow or increased vacuum could contribute to an increase positive reactivity transient by increasing the heat transfer from the reactor coolant system due to increased steam flow.
Steam dump system	Inadvertent dump valve opening		No	An inadvertent valve opening could contribute to an increase positive reactivity transient by increasing steam flow which increases the heat transfer from the reactor coolant system and adds positive reactivity.

a. Loss of Electrical Power--1, Loss of Air--2.

significantly affected by the SDS and main feedwater system failures. On this basis, the three safety grade system failures are bounded by Steam Generator Overfill Scenario Number 5.

C.3.4 Positive Reactivity Addition Scenario Number 4

The fourth step in the event scenario development process is to establish whether or not worst case initial conditions were used in the H. B. Robinson Unit 2 FSAR for the continuous rod withdrawal. The H. B. Robinson Unit 2 FSAR analyzes transients initiated at four different power levels; subcritical, 10%, 62% and 102%. By performing these analyses, the whole spectrum of possible power ranges was analyzed in the H. B. Robinson Unit 2 FSAR. The rod worth, moderator coefficient and system failures assumed were also worst case. Therefore, the initial plant conditions and assumptions used in the H. B. Robinson Unit 2 FSAR analysis for a continuous rod withdrawal event considers the worst case initial conditions.

C.3.5 Positive Reactivity Addition Scenario Number 5

The purpose of this step is to identify system failures that could aggravate the Positive Reactivity Addition Baseline Scenario (Number 1). The selected suspect systems are presented in Table C-24. Failure of any of these systems, either singularly or in combinations, could potentially aggravate a reactivity increase event due to their effects on reactor coolant temperature, the reactor coolant system boron concentration, or rod position. By reviewing the scenarios that have been developed and analyzed, it was determined that potential aggravating system failures have been addressed in other analyses except for the control rod drive system failures. Table C-25 shows the applicable scenarios that have been developed and analyzed for each selected suspect system or provides justification why further scenario development and deterministic analysis is not necessary.

TABLE C-25. JUSTIFICATIONS FOR NOT UTILIZING AGGRAVATING SYSTEMS IN ADDITIONAL INCREASE POSITIVE REACTIVITY COMPUTER ANALYSES

Suspect Aggravating System	Failure Mode	Justification
Reactor coolant system and pumps	Inadvertent pump start	A reactor coolant pump inadvertent start could contribute to a positive reactivity addition transient; however, the continuous rod assembly withdrawal or ejection bounds the effects of a coolant pump start. This conclusion was drawn on the basis that the differential temperature that results when a loop is idle will not be large enough to add sufficient reactivity to cause the transients to be worse than previously analyzed.
Chemical and volume control system	Adding nonborated water	Adding nonborated water to the reactor coolant system adds positive reactivity; however, due to the low flow rate (maximum 231 gpm), the amount of reactivity added will be low (1.1x10 k/s) and the addition will be slow. Therefore, this failure is bounded by a continuous rod assembly withdrawal or ejection.
Control rod drive system	Inadvertent withdrawal of assembly	These failures were analyzed in Sections C.3.1 and C.3.5.
Feedwater and condensate system	High flow or loss of heating	This failure is analyzed in Section C.7.5 where a high feedrate was assumed.
Steamline overpressure protection system	Inadvertent safety valve or PORV operation	This failure is bounded by the analysis performed in C.7.5 where a high steam flow rate was assumed by failing the turbine control valves and steam dump valves open.
Main steam system	An inadvertent MSIV opening	This failure is bounded by the analysis performed in C.7.5 where a high steam flow rate was assumed by failing the turbine control valves and steam dump valves open.
Turbine generator system	Inadvertent turbine control valve opening	This failure was analyzed in Section C.7.5.
Auxiliary feedwater system	Inadvertent start	This failure was bounded by the high feedwater flow rate assumed in Section C.7.5 as the flow rate of the feedwater system failure is higher than the auxiliary feedwater system.
Steam generator blowdown system	High flow rate	This failure was bounded by the high feedwater flow rate assumed in Section C.7.5 analysis as the method of contributing to this event is the result of causing high feedrate.

TABLE C-25. (continued)

Suspect Aggravating System	Failure Mode	Justification
Auxiliary steam system	High flow rate	This failure was bounded by the analysis performed in C.7.5 as the steam flow rate of the turbine generator and steam dump systems is higher.
Main condenser, evacuation and circulating water system	High circulating water flow or increase condenser vacuum	These failures were bounded by the analysis performed for C.7.5 as the high steam flow resulting from the failures of the turbine control and steam dump valves causes a higher steam flow.
Steam dump system	Inadvertent steam dump valve opening	This failure was analyzed in Section C.7.5.

The control rod drive system is the only aggravating system that was not analyzed or bounded by previous analyses. In the Positive Reactivity Addition Baseline Scenario (Number 1), a continuous rod withdrawal was analyzed. This transient would be more severe if the initiating event were a rod ejection, which is a design basis accident (DBA) instead of a rod withdrawal. The H. B. Robinson Unit 2 FSAR RCCA ejection DBA analysis was initiated at 102% reactor power by assuming that a control rod was moved to the fully withdrawn position in 0.1 s. Based on the assumptions made with regard to rod worth, initial reactor power level, moderator coefficient and the time assumed for control rod assembly withdrawal, the H. B. Robinson Unit 2 FSAR analysis is considered to be conservative. The event was terminated by a reactor scram which was initiated 0.5 s after the rod ejection and completed at 2.3 s. Rod ejection is the most limiting positive reactivity addition event and bounds all other system failures that could result in the addition of positive reactivity.

C.3.6 Systems Susceptible to Loss of Electrical Power or Loss of Air

The final step in the event scenario development process is to analyze those systems from the selected suspect system list (Table C-24) that are dependent on electrical power or air. The systems dependent on electrical power are the chemical and volume control system, the feedwater and condensate system, and the auxiliary feedwater system. Failures due to the loss of electrical power or air that could potentially create a positive reactivity addition event have been discussed in the previous section (see Section C.3.5).

C.3.7 Summary of Positive Reactivity Addition Scenarios

The continuous rod control assembly withdrawal transient and the RCCA ejection DBA analyzed in the H.B. Robinson Unit 2 FSAR bound the effects of positive reactivity addition events. The basis for this judgement is the conservative assumptions made for the H. B. Robinson Unit 2 FSAR analyzed events such as high rod worth, low moderator coefficient and short rod

withdrawal times. Also, the analysis of the selected suspect systems for a positive reactivity addition event shows that any selected suspect system failure or combination of selected suspect system failures would not make a positive reactivity addition event more severe than already analyzed in Chapter 15 of the H. B. Robinson Unit 2 FSAR.

C.4 Increase in Reactor Coolant Inventory

The next event of concern is an increase in reactor coolant inventory. The concerns associated with an increase in reactor coolant inventory are related to events that could cause reactor coolant pressure to exceed pressure limits during normal operations or during cold shutdown conditions.

In Chapter 15 of the H. B. Robinson FSAR, the limiting transient for an increase in reactor coolant inventory event is an inadvertent start of a safety injection pump while the plant is in a cold shutdown condition. There was no DBA presented for this event.

Table C-26 lists the systems which are suspect of contributing to an increase in reactor coolant inventory. These systems and their effect on increasing pressure were evaluated in Section C.2 (increase reactor coolant system pressure). Section C.2 provides an evaluation of pressure transients at normal operating conditions and at cold shutdown conditions, therefore, no further evaluation is required.

TABLE C-26. SELECTED SUSPECT SYSTEMS FOR AN INCREASE IN REACTOR COOLANT INVENTORY EVENT

System	Failure Mode	Loss of Electrical Power or Air	Safety Grade	Postulated Effects
High head safety injection system	Inadvertent start		yes	An inadvertent system start could contribute to an increase in inventory transient by adding coolant to the RCS.
Residual heat removal system	Inadvertent start		yes	An inadvertent start could contribute to an increase in reactor coolant system inventory event by adding coolant.
Chemical and volume control system	High makeup or reduced letdown flow	1, 2	no	A high makeup or reduced letdown flow could contribute to an increase in reactor coolant system inventory transient by adding coolant.
Accumulator tank system	Inadvertent injection		yes	An inadvertent accumulator injection could contribute to an increase in reactor coolant system inventory transient by adding coolant.

a. Loss of electrical power--1, loss of air--2

C.5 Decrease In Reactor Coolant Flow

The next event to be studied is a decrease in reactor coolant flow. A decrease in reactor coolant flow event is defined as a decrease in flow such that core or reactor coolant pressure boundary integrity could be threatened. The main concerns for this event are a departure from nucleate boiling ratio (DNBR) of less than 1.30 and a nuclear system pressure of greater than 2750 psia.

In Chapter 15 of the H.B. Robinson Unit 2 FSAR, the limiting transient and design basis accident are presented. Respectively, they are a loss of electrical power to all three reactor coolant pumps and a locked rotor on one pump. The following scenario development and deterministic analysis process begins with a discussion of the loss of forced reactor coolant flow transient followed by a discussion of a reactor coolant pump locked rotor DBA as presented in the H. B. Robinson Unit 2 FSAR.

The decrease in reactor coolant flow limiting transient presented in Chapter 15 of the H. B. Robinson Unit 2 FSAR is a loss of forced reactor coolant flow. A loss of coolant flow incident can result from a mechanical or electrical failure in one or more reactor coolant pumps, or from a fault in the power supply to these pumps. If the reactor is at power at the time of the incident, the immediate effect of loss of coolant flow is a rapid increase in coolant temperature. This increase could result in departure from nucleate boiling (DNB) with subsequent fuel damage if the reactor is not tripped promptly. The following trip circuits provide the necessary protection against a loss of coolant flow incident and are actuated by:

1. Low voltage on pump power supply bus,

2. Pump circuit breaker opening, and

3. Low reactor coolant flow.

Simultaneous loss of electrical power to all reactor coolant pumps at full power is the most severe credible loss of coolant flow condition. For this condition, reactor trip, together with flow sustained by the inertia of the coolant and rotating pump parts, will be sufficient to prevent fuel failure, RCS overpressure, and the departure from nucleate boiling ratio (DNBR) from going below 1.30.

The following loss of flow cases are analyzed in Chapter 15 of the H. B. Robinson Unit 2 FSAR:

1. Loss of three reactor coolant pumps with a heat output of 102% of 2300 megawatts thermal (Mwt) with three loops operating,

2. Loss of two reactor coolant pumps with a heat output of 102% of 2300 Mwt with three loops operating, and

3. Loss of two reactor coolant pumps with a heat output of 62% of 2300 Mwt with two loops operating.

The first case represents the worst credible coolant flow loss. The second and third cases are less severe. Loss of one pump above a preset power level causes a reactor trip by a low flow signal. The power level above which this trip occurs is assumed to be set at 60% of full load. Loss of one pump above 60% of full load is less severe than the second case analyzed since it will trip the reactor earlier and flow coastdown is slower. During two loop operation at power, the loss of a second single coolant pump activates a reactor trip. This case is a less severe accident than the third case presented.

The normal power supplies for the pumps are the two buses connected to the generator, one of which supplies power to one of the three pumps and the other of which supplies power to two of the three pumps. When a turbine trip occurs, the pumps are automatically transferred to a bus supplied from external power lines, and this pump will continue to supply coolant flow to the core. The simultaneous loss of power to all reactor

coolant pumps is a highly unlikely event. Following any turbine trip, where there are no electrical faults which require tripping the generator from the network, the generator remains connected to the network for at least one minute. The reactor coolant pumps remain connected to the generator thus ensuring full flow for one minute after the reactor trip before any transfer is made. Since all pumps are not on the same bus, a single bus fault would not result in the loss of all pumps.

A full plant simulation is used in the analysis to compute the core average and hotspot heat flux transient responses, including flow coastdown, temperature, reactivity, and control rod insertion effects.

Calculations of DNBR were made using steady state THINC code[10] calculations at various time points during the transient using the instantaneous values of core inlet flow and rod heat flux as inputs. This approach is conservative with respect to minimum DNBR since it overpredicts fluid enthalpy, at any point in the core, as compared to a transient calculation.

Calculations of DNBR during the transient were made using design basis peaking factors and methodology consistent with that discussed in Section 4 of the Fuel Densification Report[11].

The initial operating conditions, which are assumed to be most adverse with respect to the margin to DNB, are maximum steady-state power level, minimum steady-state pressure, and maximum steady-state inlet temperature:

2300 Mwt--3 loops operating:

Power	(1.02) (2300 Mwt) = 2346 Mwt
Pressure	2250 - 30 = 2220 psia
Inlet Temperature	546.2 + 4 = 550.2°F

1380 Mwt - 2 loops operating:

Power	(0.60 + 0.02) (2300 Mwt) = 1426 Mwt
Pressure	2250 - 30 = 2220 psia
Inlet Temperature	552.7 + 4 = 556.7°F

The highest values of the Doppler (-10×10^{-5} δk-F^{-1}) and moderator (0.0×10^{-4} δ-F^{-1}) temperature coefficients (MTC) are assumed since these result in the maximum hotspot heat flux during the initial power of the transient, when the minimum DNBR is reached. Thus, no credit is taken for compensating reactivity changes which tend to limit the severity of the transient.

Following the loss of three pumps at power, a reactor trip is actuated by either low voltage or the pump circuit breakers since the accident is due to the simultaneous loss of power to all three pumps. Both the low voltage and circuit breaker trip circuitry meet the IEEE Std. 279 criterion[12] and therefore cannot be negated by a single failure.

The time from the loss of power to all operating pumps to the initiation of control rod motion to shut down the reactor is taken as 1.6 s. This is a conservative assessment of the delay.

A low flow trip is assumed to be actuated following loss of one or two pumps, since the low flow trip results in a longer delay than the use of undervoltage or breaker trips. For the case of three-loop operation, a 2.6 s time delay prior to start of rod motion was assumed for the loss of one or two pumps. For the case of two-loop operation, a 3.82 s time delay prior to start of rod motion was assumed for the loss of one pump.

The low flow trip setting is 90% of full flow; the trip signal is assumed to be initiated at 87% of full flow, allowing 3% for flow instrumentation errors. The time from the initiation of the low flow signal to initiation of control rod motion is 1.0 s. Upon reactor trip, it is also assumed that the most reactive rod cluster control assembly (RCCA) is stuck in its fully withdrawn position, hence resulting in a minimum insertion of negative reactivity. The negative reactivity insertion upon trip is conservatively based on a 1% shutdown margin at no-load conditions.

The overall heat conductance between the fuel and the water varies considerably during the transient mostly as a result of the change of fuel gap conductance. A conservatively evaluated overall heat conductance was used in the analysis.

The DNBR remained above the limiting criterion (1.30) for both three-coolant pump operation at a core power level of 2346 Mwt, and two-coolant pump operation at 1426 Mwt. The worst loss of pump power case was the coastdown of three pumps at full power operation. The minimum DNBR for this case was 1.64. This was also the worst case in the analysis for 2200 Mwt operation, however, the minimum DNBR was considerably higher for the 2300 Mwt case because of the reduction in design hot channel factors from those used in the 2200 Mwt analysis.

The reload of the H. B. Robinson Unit 2 reactor with Exxon fuel resulted in core parameters which differed slightly from the Westinghouse fuel. To demonstrate that the Exxon fuel met the H. B. Robinson Unit 2 plant Technical Specifications, Appendix A to Facility Operating License No. DPR-23, transient analyses, including analyses of the loss of forced reactor coolant flow transient, were performed for operation at 2200 Mwt and 2300 Mwt using the Exxon Nuclear PTS-PWR Code[13]. The PTS-PWR Code results are compared with previous results obtained for H. B. Robinson Unit 2 with Westinghouse fuel for 2200 Mwt and 2300 Mwt operation. The PTS-PWR results for the transients analyzed, including the loss of forced reactor coolant flow, agreed reasonably well with the previous results obtained for Westinghouse fuel and in no case was a Technical Specification limit exceeded.

Subsequent to the above-described analyses, Exxon fuel possessing a more positive MTC was loaded into the H. B. Robinson Unit 2 reactor core. A more positive MTC provides additional positive reactivity, which results in further heatup and reduction of the thermal margin. Therefore, these transients have been reanalyzed assuming a positive MTC and Exxon fuel in the core.

The loss of coolant flow has been reanalyzed for the most severe case of a three pump coastdown--loss of power to all three primary pumps from operation at 102% of rated power (2346 Mwt). The analyses of the loss of coolant flow incident assumed beginning of cycle (BOC) kinetic coefficients with a 0.8 multiplier applied to the Doppler coefficient maximizes the core power and hot channel heat flux during these transients. The transient responses indicate that the MDNBR reached is 1.89, which exceeds the previously reported results. Further analysis of loss of forced reactor coolant flow and other transients indicate that the reduction in MDNBR resulting from tube plugging effect is negligible. The sequence of events for the trip of all three reactor coolant pumps limiting transient from the H. B. Robinson FSAR is presented in Table C-27.

The decrease in reactor coolant flow DBA presented in Chapter 15 of the H. B. Robinson FSAR is a reactor coolant pump locked rotor. In the H. B. Robinson Unit 2 FSAR a hypothetical accident analysis was performed for the postulated instantaneous seizure of a reactor coolant pump rotor. Flow through the RCS was rapidly reduced, leading to a reactor trip on a low-flow signal. Following the trip, heat stored in the fuel rods continues to pass into the core coolant, causing the coolant to expand. At the same time, heat transfer to the shell side of the steam generator is reduced, first because the reduced flow results in a decreased tube side film coefficient, and then because the reactor coolant in the tubes cools down while the shell side temperature increases (turbine steam flow is reduced to zero upon plant trip). The rapid expansion of the coolant in the reactor core, combined with the reduced heat transfer in the steam generator causes an insurge into the pressurizer and a pressure increase throughout the RCS. The insurge into the pressurizer compresses the steam volume, actuates the automatic spray system, opens the power-operated relief valves, and opens the pressurizer safety valves, in that sequence. The two power-operated relief valves are designed for reliable operation and would be expected to function properly during the accident. However, for conservatism, their pressure-reducing effect is not included in the analysis.

TABLE C-27. H. B. ROBINSON FSAR SEQUENCE OF EVENTS FOR A TRIP OF ALL THREE REACTOR COOLANT PUMPS

Time (seconds)	Event
0	Reactor operating at 2346 Mwt, 2220 psia, and 550.2°F.
0.1	Simultaneous loss of power to all three RCPs.
~0.7	Reactor trip from low voltage on pump power supply bus or pump circuit breaker opening.
1.7	Control rod insertion is initiated.
2.7	Minimum DNBR is reached (1.64).

The following cases are analyzed:

1. Locked rotor accident from a reactor coolant heat output of 2300 Mwt with three loops operating, and

2. Locked rotor accident from a reactor coolant heat output of 1380 Mwt with two loops operating.

At the beginning of the postulated locked rotor accidents; i.e., at the time the shaft in one of the reactor coolant pumps is assumed to seize, the plant is assumed to be in operation under the most severe steady state operating conditions. The plant is assumed to be operating at 102% of nominal full power with three pumps operating (2346 Mwt), and at 62% of nominal full power with two pumps operating (1426 Mwt), based on the maximum expected calorimetric error. Inlet temperature is assumed to be 4°F above its programmed value to allow for the 2°F deadband on control rod motion and a maximum temperature error of 2°F (nominal inlet temperature with three pumps operating is 546.2°F and assumed to be 552.7° with two loops operating). Reactor coolant pressure is conservatively estimated as 30 psi above nominal pressure of 2250 psia to allow for errors in the pressure measurement and control channels.

A digital computer code was used to determine the peak pressure in the RCS under the postulated accident conditions and to obtain the nuclear power as a function of time to be used later in the analysis.

After pump seizure, nuclear power is rapidly reduced because of the control rod insertion upon plant trip and void shutdown.

In this analysis, the time from pump seizure to initiation of control rod motion was taken as 1.04 s for three loops in operation and 1.06 s for two loops in operation. Shutdown reactivity is conservatively based on a 1% shutdown margin at no-load conditions. A zero MTC was assumed; thus, no credit is taken for compensating reactivity changes which tend to limit the severity of the transient.

No credit was taken for the pressure-reducing effect of the pressurizer relief valves, steam dump, and controlled feedwater flow after plant trip. Although these operations are expected to occur and would result in a lower peak pressure, an additional degree of conservatism is provided by ignoring their effect.

The reactor pressurizer safety valves start operating at 2500 psia, and their capacity for steam relief is 29.7 ft^3/s.

Heat flux transients following the pump seizure were evaluated by a detailed digital computer model with the input of the nuclear power, the pressure, and the coolant conditions previously calculated as functions of time.

Calculations of the extent of DNB in the core during the accidents were performed using the THINC model with the heat flux, the coolant flow decay, and the coolant conditions calculated as a function of time.

In order to estimate the severity of the accident in the core as far as the integrity of the fuel rods are concerned, the thermal behavior of the fuel located at the hotspot after DNB was investigated. Results obtained from an analysis of the "hotspot" condition represent the upper limit with respect to cladding temperature, cladding melting, and zirconium-steam reaction.

For conservatism, DNB was assumed to start at the beginning of the accident and the heat transfer coefficient between cladding and coolant was reduced suddenly from its steady-state value to 0.7 times the film boiling value at time = 0, without any period of transition boiling. The safety factor of 0.7 was assumed for conservatism in evaluating the film boiling coefficient.

The magnitude and time dependence of the heat transfer coefficient between fuel and cladding have a pronounced influence on the thermal results. The larger the value of this coefficient, the more heat is

transferred between pellet and cladding. For the first part of the transient, a high gap coefficient produces higher cladding temperatures since the heat stored and generated in the fuel pellet tries to redistribute itself in the cooler cladding. This effect of the gap coefficient, however, is reversed when the cladding temperature exceeds the pellet temperature in cases when the zirconium-steam reaction is present.

Since it was found that, in the worst case examined, the cladding temperature exceeded 1800°F, it was necessary to consider the possibility of a zirconium-steam reaction. The zirconium-steam reaction can become significant above this temperature. This phenomenon was taken into account for this analysis.

The results of the analyses performed for 2300 Mwt were evaluated to determine the extent of core damage, if any, due to this incident and to determine the peak RCS pressure during the incident.

The peak pressure reached was 2570 psia. The minimum DNBR as calculated by the THINC code for both cases was greater than 1.30. However, since the water quality was greater than the range over which the DNB correlation was developed, it was conservatively assumed that DNB would occur immediately after the start of the transient.

The peak cladding temperature calculated after DNB is less than the 2070°F reported in the Fuel Densification Report, and is well below the limiting value of 2700°F. This is due to the lower hotspot peaking factor, a revised fuel densification model, and high density fuel which results in a lower hotspot heat flux and fuel temperature at the uprated power.

The number of fuel rods which could possibly experience a DNBR of lower than 1.3 was calculated at 2200 Mwt to be considerably less than 10% of the total fuel rods. The number of fuel rods at 2300 Mwt which could possibly experience a DNBR of less than 1.3 is lower than the number reported for 2200 Mwt, since the reduction in the enthalpy rise hot channel factor resulting from a higher density fuel more than offsets the increased power.

1. Since the peak pressure reached during the transient is 2570 psia with the integrity of the primary coolant system not being endangered, this value can be considered as an upper limit, because of the conservative assumptions used in the H. B. Robinson FSAR analysis as given below:

   a. Credit was not taken for the negative moderator coefficient,

   b. It was assumed that the pressurizer relief valves were inoperative, and

   c. The steam dump was assumed to be inoperative.

2. Less than 10% of the fuel rods exhibited a DNBR of less than 1.3.

3. The peak cladding surface temperature will be less than 2070°F calculated at 2200 Mwt in the Fuel Densification Report, and well below the limiting value of 2700°F.

4. The locked rotor event was reanalyzed and the minimum DNBR was found to 1.40 for Exxon fuel in the reactor core.

For this event, up to one percent fuel damage is acceptable. Significant margin to the acceptance criteria is demonstrated with the raised coefficient.

The sequence of events for the locked rotor DBA from the H. B. Robinson FSAR is presented in Table C-28.

C.5.1 Decrease in Reactor Coolant Flow Baseline Scenario (Number 1)

The first step in the decrease in reactor coolant flow scenario development process is to deterministically examine the effects of loss of all three reactor coolant pumps. The Decrease in Reactor Coolant Flow Baseline Scenario (Number 1) is similar to the H. B. Robinson FSAR analysis

TABLE C-28. H. B. ROBINSON FSAR SEQUENCE OF EVENTS FOR A LOCKED ROTOR

Time (seconds)	Event
0.0	2346 Mwt, 2280 psia, 550.2°F. Reactor coolant pump rotor seizes.
1.04	Control rods begin to insert into the core.
~2.5	Peak pressure reached (2400 psia).

for loss of all three reactor coolant pumps with the following exceptions. The delay time from the loss of power until the control rods begin insertion was 1 second instead of the 1.6 seconds used in the FSAR analysis. The 1 second value is more realistic given the actual response times of the plant equipment. The other exception is the values used for the moderator temperature and the doppler coefficients. The RELAP5 computer model groups all core temperature coefficients into one value, and a conservative value was utilized for this analysis.

To initiate the transient, it was assumed that power was instantaneously lost to all three reactor coolant pumps. Reactor power was 102% of licensed power (2346 Mwt) and all system controls were operating normally in the automatic mode. Pressurizer pressure was assumed to be at the low end of the operating band (2220 psia) to reduce the amount of initial subcooling in the RCS.

A sequence of events for this transient is provided in Table C-29. The transient is terminated by a reactor trip that occurs 1.0 s after loss of power to the RCPs. The maximum hot leg temperature of 611°F is reached 2.8 s after initiation of the event. Due to RELAP5 code limitations, the DNBR cannot be calculated until it falls below 1.40. During this analysis the DNBR did not decrease to the point where the calculation was made and the minimum subcooling experienced was 42°F, which provides a margin of safety. On this basis and the fact that the baseline analysis plots closely follow the H. B. Robinson FSAR analysis plots, the baseline analysis is considered to be an accurate description of the scenario outcome.

C.5.2 Decrease in Reactor Coolant Flow Scenario Number 2

The second step in the event scenario development process was to determine if any non-safety grade systems were used to mitigate the Decrease in Reactor Coolant Flow Baseline Scenario (Number 1) and then postulate its failure. This event was mitigated only by safety grade equipment, the reactor protection system.

TABLE C-29. SEQUENCE OF EVENTS FOR THE DECREASE IN REACTOR COOLANT FLOW BASELINE SCENARIO (NUMBER 1)

Time (seconds)	Event
0.0	Reactor at 102% power all controls in automatic.
1.0	Loss of power to all three RCPs.
2.0	Reactor trip, turbine trip, start of motor driven auxiliary feedwater pumps.
3.8	Hot leg temperature peaks at 611°F.
~4.0	RCS pressure peaks at ~2250 psia.
10.0	Feedwater control valves close.

C.5.3 Decrease in Reactor Coolant Flow Scenario Number 3

The third step in the event scenario development process was to examine the Decrease in Reactor Coolant Flow Baseline Scenario (Number 1) to determine if a safety grade system failure had been assumed. In this case, no safety grade failures had been assumed. The selected suspect systems list (Table C-30) for a decrease in reactor coolant flow event was reviewed for the purpose of identifying safety grade system failures that could contribute to a reactor coolant flow decrease event. Table C-30 shows the selected suspect systems for a decrease in reactor coolant flow, and of the two suspect systems, one is safety grade, the residual heat removal system.

A failure of the RHR was not analyzed on the computer since the failure mode of concern is no flow which indicates that the reactor plant is in a status that requires RHR operation. For the plant to be in this condition, the reactor must be shutdown with a low reactor coolant pressure and temperature. If a low RHR flow condition were experienced while the reactor plant was in the decay heat removal mode, there would be an increase in reactor coolant system pressure, however, the increase would be slow enough that operator actions could be initiated to prevent any threat to core integrity. The other concern during this event is DNB; however, since the reactor is shutdown, DNB is not a problem. Based on the above discussion, it was not deemed necessary to perform a computer analysis of a decrease in reactor coolant flow event that incorporated an aggravating failure of the RHR system.

C.5.4 Decrease in Reactor Coolant Flow Scenario Number 4

The fourth step in the event scenario development process was to establish whether or not worst case initial plant conditions were utilized in the H. B. Robinson FSAR analysis for a decrease in reactor coolant flow event.

TABLE C-30. SELECTED SUSPECT SYSTEMS FOR A DECREASING REACTOR COOLANT FLOW EVENT

System	Failure Mode	Loss of Electrical Power or Air	Safety Grade	Postulated Effects
Reactor coolant system and pumps	No Flow	1	No	Reactor coolant pump low flow can contribute to a low flow transient since the main source of core flow is the reactor coolant pump head. Therefore, a loss of pump flow results in a decrease in core flow.
Residual heat removal	No Flow	1, 2	Yes	Residual heat removal system low flow can contribute to a low flow transient since the RHR pumps provide flow through the core during low temperature, low pressure conditions. Therefore, a low flow from the RHR pumps could result in a decrease in core flow.

a. Loss of electrical Power--1, Loss of air--2

For the loss of forced reactor coolant flow event, it was assumed in the H. B. Robinson FSAR that the plant was operating at 102% reactor power when there was an instantaneous trip of all three reactor coolant pumps. The reactor power level is considered to be conservative since the assumed power is higher than the power levels at which the plant would normally be operating which would make the event more severe than it would be at normal operating power levels. Conservative values were also utilized in the FSAR analysis for the other plant parameters, such as inlet temperature and RCS pressure. On this basis, the initial plant conditions are considered to be conservative and worst case.

C.5.5 Decrease in Reactor Coolant Flow Scenario Number 5

The purpose of this step is to identify system failures from the suspect systems list (Table C-30) that would have the greatest effect in aggravating the baseline scenario, or in other words, produce the worst case aggravated scenario in an attempt to exceed the selection criteria. The one possible aggravating system on the suspect system list that could have an affect during pressurized operation is the reactor coolant system and pumps. Since this is the system that is failed in the Decrease in Reactor Coolant Flow Baseline Scenario (Number 1), the only way to aggravate the scenario is to consider a more severe failure in this system in conjunction with the initially postulated failure. This was accomplished by having a seized rotor accident (DBA) occur concurrently with the baseline scenario. The residual heat removal system failure mode is only applicable during decay heat removal at low system temperatures and pressures. The justification for not performing a computer analysis for the RHR system failure mode is provided in Table C-31.

The initial plant conditions for Decrease in Reactor Coolant Flow Scenario Number 5 are reactor power at 102% and all control systems in the automatic mode. For the initiating event it is assumed that power is lost to all three RCPs and the rotor seizes on the "C" RCP. The rotor is assumed to take 1 s to come to a complete stop because an instantaneous

TABLE C-31. JUSTIFICATIONS FOR NOT UTILIZING AGGRAVATING SYSTEMS IN ADDITIONAL DECREASE FLOW COMPUTER ANALYSES

Suspect Aggravating System	Failure Mode	Justification
Reactor coolant system and pumps	No flow	Loss of power to all three RCPs was analyzed in the FSAR analysis and in the baseline analysis (see Section C.5.1). A shaft seizure on one RCP with a simultaneous loss of power to the other two pumps was analyzed in an attempt to reach a lower minimum DNBR than in the FSAR analysis; the results were that the subcooling did not decrease low enough for the model to calculate DNBR. Our evaluations showed no other realistic failure scenario that could possibly exceed the FSAR analysis results.
Residual heat removal system	No flow	During low temperature, low pressure conditions when the RHR system is circulating water through the RCS, a loss of flow would result in an increase in core temperature, however, this increase will be slow enough that adequate time would be available for alarms to sound and the operators to take corrective actions to restore cooling flow before any core temperature limits are exceeded.

seizure could not be accommodated by the computer code. This time delay is not as conservative as an instantaneous seizure, but considering the amount of energy associated with the rotating mass of the pump and motor, one second is conservative when compared to the time that would realistically be required to bring that rotating mass to a complete stop. The non-safety grade pressurizer PORVs were assumed to fail to open to relieve RCS pressure as it increased during the transient. Pressurizer pressure was assumed to be at the low end of the operating band (2220 psig) to reduce the amount of initial subcooling in the RCS.

A sequence of events for this transient is provided in Table C-32. The transient is terminated by a reactor trip which started rod insertion 1.0 s after the loss of power to the RCPs. The maximum pressurizer pressure (2385 psia) is reached 3.0 s after initiation of the event. Due to RELAP5 code limitations, DNBR cannot be calculated until it falls below 1.40. During this analysis the DNBR did not decrease to the point where the calculation was made. The minimum subcooling experienced in the core is 30°F, which although less than the 42°F subcooling that occurred in the baseline analysis, still provides a margin of safety for the reactor. The maximum pressure for this transient is higher than the pressure peak in the baseline analysis, and the minimum subcooling is lower than for the baseline; however, in both cases the analysis results for this transient are bounded by those experienced in the H. B. Robinson FSAR DBA (Locked Rotor) analysis. It is, therefore, concluded that this transient did not exceed the selection criteria for a decrease in reactor flow event.

C.5.6 Systems Susceptible to Loss of Electrical Power or Air

The final step in the scenario development process was to analyze those systems whose failure modes were dependent on electrical power or air. The systems that are dependent on electrical power or air are the RHR and the reactor coolant system and pumps (see Table C-30). Failures due to loss of electrical power or air that could potentially create a decrease in reactor coolant system flow event have been discussed in previous sections (see Sections C.5.1 and C.5.3).

TABLE C-32. SEQUENCE OF EVENTS FOR DECREASE IN REACTOR COOLANT FLOW SCENARIO NUMBER 5

Time (seconds)	Event
0.0	Reactor at 102% power with all controls in automatic.
1.0	Loss of power to all three RCPs and "C" RCP starts deceleration. Reactor and turbine trip signals generated.
2.0	"C" RCP is completely stopped and locked up. Control rods begin to insert.
2.5	Steam line "C" check valve closes.
3.1	The energy removed by the steam generators exceeds core power.
4.0	The maximum pressurizer pressure of 2385 psia is reached.
6.0	Flow reverses in primary Loop "C".

C.5.7 Summary of Decrease in Reactor Coolant Flow Scenarios

The instantaneous trip of all three reactor coolant pumps and the locked rotor DBA analyzed in Chapter 15 of the H. B. Robinson FSAR bound the effects of a decrease in reactor coolant flow. The basis for this judgement is the conservative assumptions made for the two FSAR analyses, such as reactor power at 102% of rated power, PORVs failing to operate, no steam dump flow, and that our analysis of the selected suspect systems for a decrease in reactor coolant flow event shows that any suspect system failure or combination of system failures would not make the transients more severe than presented in Chapter 15 of the H. B. Robinson FSAR.

C.6 Decrease Reactor Coolant Inventory Scenarios

The next event to be studied is a decrease in reactor coolant inventory. A decrease in reactor coolant inventory event is defined as a loss of reactor coolant such that core integrity could be threatened. Since the main threat to core integrity is overheating, this evaluation involved system failures that could possibly cause the core temperature to exceed 2200°F.

In Chapter 15 of the H. B. Robinson FSAR, the limiting transient and the DBA for a decreasing reactor coolant inventory event are presented. They are respectively, a steam generator tube rupture at full power and a double-ended cold leg guillotine pipe break. The limiting transient is not analyzed in this section. However, it is covered in a separate evaluation since a steam generator tube rupture has concerns in addition to the loss of coolant inventory such as increasing steam generator level and release of radioactive materials to the atmosphere.

The decreasing reactor coolant inventory event scenario development and deterministic analysis process was initiated by analyzing the large break loss of coolant accident as presented in the H. B. Robinson FSAR. The following are selected portions of the Chapter 15 large breack LOCA analysis taken directly from the H. B. Robinson FSAR.

For the purpose of the H. B. Robinson FSAR LOCA analyses, a major LOCA is defined as a rupture 1.0 ft^2 or larger of the Reactor Primary Coolant System piping, including the double-ended rupture of the largest pipe in the RCS or of any line connected to that system up to the first closed valve.

Should a major break occur, depressurization of the RCS results in a pressure decrease in the pressurizer. A reactor trip signal occurs when the pressurizer low pressure trip setpoint is reached. A safety injection system (SIS) signal is actuated when the appropriate setpoint (high containment pressure) is reached. These countermeasures will limit the consequences of the accident in two ways:

1. Reactor trip and borated water injection complement void formation in causing a rapid reduction of power to a residual level corresponding to fission product decay heat, and

2. Injection of borated water provides heat transfer from the core and prevents excessive cladding temperatures.

At the beginning of the blowdown phase, the entire RCS contains subcooled liquid, which transfers heat from the core by forced convection, with some fully developed nucleate boiling. After the break develops, the time to departure from nucleate boiling (DNB) is calculated, consistent with Appendix K of 10 CFR 50. Thereafter, the core heat transfer is unstable, with both nucleate boiling and film boiling occurring. As the core becomes uncovered, both turbulent and laminar forced convection and radiation are considered as core heat transfer mechanisms.

When the RCS pressure falls below 600 psia, the accumulators begin to inject borated water into the RCS. The conservative assumption is made that injected accumulator water bypasses the core and goes out through the break until the termination of bypass. This conservatism is again consistent with Appendix K of 10 CFR 50.

Large break calculations were performed for both guillotine and split break configurations. Three guillotine cases were run with discharge coefficients of 1.0, 0.8, and 0.6. Two split cases were run with areas of 1.0 and 0.8 times the equivalent double-ended break. Three sensitivity studies were performed for the 1.0 double-ended, cold leg guillotine (DECLG) case, one with a homogeneous upper head model, one without SG tube plugging, and one with the previous LPSI flow. The 0.8 DECLG was calculated to be the limiting break with a peak cladding temperature (PCT) of 2152°F at a total peaking factor of 2.2. All analyses were performed in accordance with Appendix K of 10 CFR 50 at a total peaking of 2.2, except for the prior LPSI flow sensitivity study (performed before LPSI injection point modifications), which used the previous 2.3 total peaking factor.

The analyses for H. B. Robinson Unit 2 with Exxon Nuclear Company (ENC) fuel shows that the maximum calculated cladding temperature of 2152°F occurs for the double-ended guillotine configuration with a discharge coefficient of 0.8 at a total linear heat generation rate (LHGR) of 13.43 kW/ft and a 2.2 total peaking factor. This represents 102% of operation at 13.17 kW/ft. The maximum local metal-water reaction calculated is 7.9% at 148 s, and the total core wide metal-water reaction is approximately 0.7 to 0.8%, which is well below the limits set by the criteria of 10 CFR 50.46.

For breaks up to and including the double-ended severance of a reactor coolant pipe, the H. B. Robinson Unit 2 ECCS will meet the Acceptance Criteria as presented in 10 CFR 50.46 with ENC fuel operating in accordance with the LHGR limits noted above. That is:

1. The calculated peak fuel element cladding temperature does not exceed the 2200°F limit.

2. The amount of fuel element cladding that reacts chemically with water or steam does not exceed 1% of the total amount of zircaloy in the reactor.

3. The cladding temperature transient is terminated at a time when the core geometry is still amenable to cooling. The hot fuel rod cladding oxidation limits of 17% are not exceeded during or after quenching.

4. The core temperature is reduced and decay heat is removed for an extended period of time, as required by the longlived radioactivity remaining in the core.

The above analyses for H. B. Robinson Unit 2 were performed on the basis of 6% of the tubes in the SG being plugged. Analyses with greater amounts of tube plugging, should operation with such levels of tube plugging become necessary, were prepared. Three SG tube plugging cases were analyzed: 6, 10 and 15%.

Results of these analyses confirm that the current plant total LHGR limit of 13.43 kW/ft (corresponding to an F_Q of 2.2) assures conformance with 10 CFR 50.46 criteria for all levels of tube plugging analyzed, i.e. 6 to 15%.

The total LHGR was raised for each of the three SG plugging cases analyzed until the PCT was within 50°F of the 2200°F limit. The results showed that H. B. Robinson Unit 2 can be operated in conformance with 10 CFR 50.46 with total LHGR limits of 14.48, 14.36, and 14.21 kW/ft for the 6, 10, and 15% SG tube plugging cases, respectively,. The corresponding F_Q limits are 2.42, 2.40, and 2.37, respectively.

The sequence of events for the H. B. Robinson FSAR decreasing inventory design basis accident is presented in Table C-33.

C.6.1 <u>Summary of Decrease Reactor Coolant Inventory Scenarios</u>

The H. B. Robinson FSAR loss of coolant accident analysis was designed to be a bounding case evaluation (that is the worst possible failures and plant conditions are assumed such that the effects of all other individual system failures would be less severe than the bounding case effects). The scenario

TABLE C-33. H. B. ROBINSON FSAR SEQUENCE OF EVENTS FOR LARGE BREAK LOSS OF COOLANT ACCIDENT

Time (s)	Event
0.0	102% reactor power.
0.1	Double-ended cold leg guillotine break occurs. Reactor coolant pumps trip.
0.6	Safety injection signal.
3.21	Accumulator injection into broken loop.
11.92	Accumulator injection into intact loop.
24.50	End-of-blowdown.
25.26	End-of-bypass.
25.60	Safety injection pump injection to primary coolant system.
48.26	Accumulator empty.
48.52	Bottom of core recovery.
123.51	Peak cladding temperature reached.

was developed as a bounding case by implementing conservative assumptions that belonged to one of two categories based on whether the assumptions affected plant conditions or the computer model. The following are some of the assumptions affecting plant conditions that were utilized in the DBA LOCA analysis:

1. 102% reactor power as the initial power

2. Non-safety grade control systems were assumed to fail

3. A single active failure in the engineered safety features was assumed

4. The most reactive control rod assembly was assumed to be stuck in the fully withdrawn position

5. The worst case initiating event was assumed.

The second category of conservative assumptions implemented for the LOCA analysis was built into the RELAP4-EM computer model (see Appendix B). These assumptions were required by Appendix K of 10 CFR 50 and affected the following critical points in the calculations:

1. The initial stored energy in the fuel

2. Fission heat

3. Decay actinides

4. Fission product decay

5. Metal-water reaction rate

6. Reactor internals heat transfer

7. Primary to secondary heat transfer.

As part of this evaluation, a failure modes and effects analysis (FMEA) was performed on the H. B. Robinson, Unit 2 systems[14,15,16]. The FMEA identified eleven systems as having the potential to aggravate a LOCA scenario (see Table C-34, Selected Suspect Systems for a Decreasing Reactor Coolant Inventory Event).

The failure modes of the eleven suspect systems identified by the FMEA were compared to the failures assumed for the FSAR analysis. The comparison determined that the effects of the FSAR failures bounded the effects of the suspect system failures. The logic utilized to draw this conclusion is presented in Table C-35.

The final area to be discussed is the differences between the computer models used for the calculations. The FSAR analysis was performed using RELAP4-EM which is a conservative "evaluation model" set up to meet the 10 CFR 50 Appendix K requirements. The calculations made for this analysis used the RELAP5 computer model which is a "best estimate" model. Based on the fact that the evaluation model incorporates Appendix K conservatisms and the best estimate model does not, the best estimate model will provide less conservative results than the evaluation model. The evaluation model calculated a maximum peak cladding temperature (PCT) of 2152°F which is below the 10 CFR 50.46 limit of 2200°F. Since the best estimate model will predict a more realistic value for PCT (it is expected to be significantly lower), the FSAR analysis would bound the RELAP5 analysis.

Given that the failures assumed for the FSAR analysis bound the suspect system failures and that the FSAR analysis computer model calculation bounds the RELAP5 calculations, the H. B. Robinson analysis is considered to be worst case and would not be exceeded if additional failures were assumed. Based on the above discussion, computer analysis to verify the effects of the identified aggravating systems is not deemed necessary.

TABLE C-34. SELECTED SUSPECT SYSTEMS FOR A DECREASING REACTOR COOLANT INVENTORY EVENT

System	Failure Mode	Loss of Electrical Power or Air	Safety Grade	Postulated Effects
Reactor coolant system and pumps	No flow	1	No	A loss of reactor coolant pump flow would cause a decrease of heat transfer which could cause reactor coolant system pressure to increase. An increased pressure could cause a higher coolant loss rate and could cause a PORV or safety valve to open.
Pressurizer overpressure protection system	Inadvertent SRV or PORV opening		Yes	An inadvertent valve opening could contribute to a decrease inventory transient by causing a coolant loss from the open valve.
Residual heat removal system	No flow	1, 2	Yes	A RHR low flow condition while in decay heat removal operation could cause reactor coolant system pressure to increase. An increase pressure could cause a relief valve on the RHR system to open.
Chemical and volume control system	High letdown or no charging flow	1, 2	No	A high letdown or low charging flow could contribute to a decreasing inventory transient by removing more coolant from the reactor coolant system than is being replaced.
Pressurizer pressure control system	Pressure is controlling high	2	No	Pressurizer pressure controlling high could contribute to a decrease inventory transient by causing the coolant loss rate to be high or causing a PORV or safety valve to open.
Control rod drive system	Rod ejection		No	A control rod ejection could contribute to a decreasing inventory transient as this type of failure could cause a breech of the reactor coolant system boundary, which is a LOCA.

TABLE C-34. (continued)

System	Failure Mode	Loss of Electrical Power or Air	Safety Grade	Postulated Effects
Main steam system	Inadvertent MSIV closure	1	Yes	An inadvertent valve closure could contribute to a decreasing inventory transient as it would cause a decrease in heat transfer which could cause a pressure increase. A pressure increase could cause an inventory loss to be greater or cause a PORV or safety valve to open.
Turbine generator system	Inadvertent turbine control valve closure	1	No	An inadvertent valve closure could contribute to a decreasing inventory transient as it would cause a decrease in heat transfer which could cause a pressure increase. A pressure increase could cause an inventory loss to be greater or cause a PORV or safety valve to open.
Steam dump system	Inadvertent steam dump valve closure	1, 2	No	An inadvertent valve closure could contribute to a decreasing inventory transient as it would cause a decrease in heat transfer which could cause a pressure increase. A pressure increase could cause an inventory loss to be greater or cause a PORV or safety valve to open.
Steam generator	Tube rupture		Yes	This failure mode could contribute to a decrease coolant inventory event, however, tube rupture is an independent study and will be presented separately.
Condenser, evacuation and circulating water system	No circulating water flow or low condenser vacuum	1	No	A loss of condenser vacuum causes a reduction of heat transfer from the reactor coolant system which could cause a pressure increase. A pressure increase could cause an increase in inventory loss rate and a PORV or safety valve to open.

a. Loss of electrical power--1; Loss of air--2

TABLE C-35. JUSTIFICATIONS FOR NOT UTILIZING AGGRAVATING SYSTEMS IN ADDITIONAL DECREASE INVENTORY COMPUTER ANALYSES

Suspect Aggravating System	Failure Mode	Justification
Reactor coolant system and pumps	No flow	The FSAR LOCA analysis assumes that the reactor coolant pumps are tripped at the outset of the accident and includes the effects of pump coastdown in the blowdown analysis. Therefore, this failure mode is incorporated into the FSAR analysis.
Pressurizer overpressure protection system	Inadvertent PORV or safety valve opening	The effects of an inadvertent PORV or safety valve opening on a double ended cold leg guillotine break would be of no consequence. The area of a 4 in. diameter safety valve is approximately 12.5 square in. which is a small fraction of the 1510 square in. of the guillotine break. The analyzed depressurization of the RCS is so fast that the failure open of an safety valve or PORV would not be noticeable.
Residual heat removal (RHR) system	No flow	The portion of the RHR system that performs the LPSI function is safety grade and is designed and analyzed to fill that function assuming a single active component failure (per 10 CFR 50 Appendix K) during a LOCA. If the system were to fail when in the RHR recirculation mode at low temperature and low pressure conditions, the pressure could increase to the low temperature PORV setpoint, however, the loss of inventory involved by the lifting of a PORV would be bounded by the analyzed DBA LOCA. Also, as required by General Design Criteria 34, a means is available, utilizing safety grade equipment, to remove decay heat given the most limiting single failure in the RHR system.
Chemical and volume control system	High letdown or no charging flow	The effects of a high letdown flowrate would be minimal for a LOCA since the combined flowrate of all three letdown orifices is 166 gpm and this flowpath would be isolated early in the accident when the safety injection actuation signal (SIAS) is received 0.5 s after the break occurs. The charging pumps would go to full flow during a LOCA to try and maintain the pressurizer level, however, the total capacity for all three pumps is 231 gpm which is of small consequence when compared with the 375 gpm per pump for high head safety injection and 3750 gpm per pump for LPSI.

TABLE C-35. (continued)

Suspect Aggravating System	Failure Mode	Justification
Pressurizer pressure control system	Pressure is being controlled high	The effect of having the pressurizer and RCS pressure high at the outset of a LOCA could result in a higher break flow during the initial moments of the accident, however, a 30 psi increase (from the normal operating pressure to the high pressure alarm point) would have a minimal effect on the break flow, especially considering that the pressure falls to below the 615 psia accumulator pressure in less than 12 seconds.
Control rod drive system	Rod ejection	A control rod ejection could result in a breech of the RCS boundary which would cause a decrease in RCS inventory, however, this LOCA would be bounded by the double ended guillotine break. This event was not used to aggravate the DBA because it would have a minimal effect when a CRD mechanism housing break size was compared to the double ended break of the cold leg. Also, our evaluation failed to determine any feasible mechanism that could result in a rod ejection that is related in any way with a LOCA.
Main steam system	Inadvertent MSIV closure	A MSIV closure could reduce the heat removal from the primary thereby causing an increase in RCS pressure and break flow. However, there are several factors that tend to minimize the effects of this failure mode. A reactor trip at the outset of the LOCA would cause a turbine trip which would reduce the steam flow. The loss of reactor coolant pumps and rapid loss of RCS coolant and pressure would reduce the heat transfer in the steam generators. Also, the MSIVs would receive an isolation signal at the second containment pressure setpoint.
Turbine generator system	Inadvertent turbine control valve closure	This failure mode could reduce the heat removal from the primary which could cause an increase in RCS pressure and break flow, however, the FSAR analysis incorporated a turbine trip from a reactor trip at the outset of the accident. Therefore, this aggravator was analyzed and need not be further evaluated.

TABLE C-35. (continued)

Suspect Aggravating System	Failure Mode	Justification
Steam dump system	Inadvertent steam dump valve closure	The steam dump system should function to remove heat from the primary to reduce the RCS pressure and thereby reduce break flow. An inadvertent steam dump valve closure would reduce the heat removal rate. The FSAR DBA LOCA analysis assumed a loss of offsite power which would result in a loss of condenser vacuum which would disable the steam dump system within seconds of the loss of power. Therefore, this aggravator was analyzed and need not be further evaluated.
Steam generator	Tube rupture	A steam generator tube rupture is a LOCA but it would be bounded by the double ended cold leg guillotine break. This failure will also be analyzed as a separate event because of its uniqueness in that it affects several different selection criteria. As an aggravator to the DBA LOCA a tube rupture would have a minimal effect due to the small tube diameter when compared with the RCS cold leg piping.
Condenser, evacuation, and circulating water systems	Low condenser vacuum or no circulating water flow	These FSAR DBA LOCA analysis assumed a loss of offsite power which would de-energize the evacuation pumps and circulating water pumps and result in a rapid loss of condenser vacuum. Therefore, this aggravator was analyzed and need not be further evaluated.

C.7 Steam Generator Overfill Scenarios

The next event of concern is the steam generator overfill event. A steam generator overfill event is defined as an undesired increase in steam generator water level to the point where moisture enters the main steam line. A decrease in the steam dome steam quality is not considered to be an overfill problem until the steam generator narrow range (NR) level is greater than the high level setpoint of 75%.

In Chapter 15 of the H. B. Robinson Unit 2 FSAR the limiting operational transient for a steam generator overfill event is a step increase in feedwater flow to one steam generator from 0 to the nominal full load value.

There is no DBA identified in Chapter 15 of the H. B. Robinson Unit 2 FSAR for a steam generator overfill event. To form a basis for the steam generator overfill event scenario development and analysis process that follows, the increase in feedwater flow transient, as presented in Chapter 15 of the H. B. Robinson Unit 2 FSAR, will be discussed. The following are selected sections of this transient analysis taken directly from the H. B. Robinson Unit 2 FSAR.

During startup and at plant loads below approximately 10 percent, feedwater to the steam generators is controlled with the feedwater bypass control valves rather than with the main feedwater control valves. Under these conditions, the main feedwater control valves are normally in the fully closed position.

Even though the accidental opening of a main feedwater control valve at low load is quite unlikely since the valves are not used at low loads, the reactivity insertion rate at no load following the malfunction of a steam generator main feedwater control valve has been calculated with the following assumptions:

1. A step increase in feedwater flow to one steam generator from 0 to the nominal full load value for one steam generator,

2. The most negative reactivity moderator coefficient at end of life,

3. A constant feedwater temperature of 70°F,

4. Neglect of the heat capacity of the RCS and steam generator shell metal, and

5. Neglect of the energy stored in the fluid of the unaffected steam generators.

The maximum reactivity insertion rate was found to be 3.9×10^{-4} Δk/second, which is less than the reactivity insertion rates analyzed in rod withdrawal accidents from a subcritical condition ($6 \times 10^{-4} \Delta k$/sec). If the accident occurs with the plant just critical at no load, the reactor may be tripped by the power range flux level trip (low setting) set at approximately 25 percent or by the source or intermediate range flux level trips. Since the reactivity insertion rate is less than that analyzed for rod withdrawal accidents from a subcritical condition, there is a large margin to DNB. Depending upon the temperature of the feedwater and the magnitude of the flow, the core may not reach the flux level trip setpoints. In that case, due to the low core power, there will again be a large margin to DNB.

Continuous addition of cold feedwater after a reactor trip is prevented by:

1. An interlock which closes all main feedwater control valves by venting the valve actuators following a plant trip if the RCS temperature is below approximately 554°F.

2. An interlock which closes the main and bypass feedwater control valves by venting the valve actuators following 2/3 high steam generator level signals in a steam generator. This interlock closes the valves only for the affected steam generator and is redundant down to two solenoids per feedwater control valve, which vent the valve actuator.

A continuous cooldown caused by the addition of cold feedwater after a reactor trip is prevented even in the case of a failure in a valve. The reduction of RCS temperature, pressure, and pressurizer level caused by a cooldown will lead to a safety injection (SI) signal on low pressurizer pressure. The SI signal will trip the main feedwater pumps and close the main and bypass feedwater control valves. This will stop all feedwater even if a valve remains in the fully open position.

The FSAR analysis does not provide sufficient detail to develop a sequence of events for this transient.

C.7.1 Steam Generator Overfill Baseline Scenario (Number 1)

The Steam Generator Overfill Baseline Scenario (Number 1) is similar to the H. B. Robinson Unit 2 FSAR analysis presented above.

The initial plant conditions for the Steam Generator Overfill Baseline Scenario (Number 1) are the plant at 5% reactor power and the rod control, feedwater control, and turbine EHC in manual with all other systems controlling in automatic. A low initial power was used in the calculation because it resulted in a larger possible steam flow-feed flow mismatch.

The transient was initiated by opening the Steam Generator A (SGA) main Feedwater (MFW) control valve at a rate of 10%/s. The transient was terminated after 240 s when it was determined that the SGA narrow range (NR) level had peaked. The opening of the SGA MFW control valve at 10%/s resulted in an increase in feedwater flow into SGA from 28 lbm/s to

1295 lbm/s by 10 s. The feedwater flow rate remained essentially constant until the MFW pump was tripped and the SGA feedwater line was isolated due to the SGA NR level reaching 75%. Motor-driven auxiliary feedwater flow was started when the MFW pump was tripped. The auxiliary feedwater preferentially flowed into SGA for the remainder of the calculation (the auxiliary feedwater flows from a common header into the steam generator with the lowest pressure).

The maximum NR level reached in SGA was 96.6% at 210 s at which time there was also a drop in steam dome steam quality. Since this scenario analysis results exceed Selection Criterion 7, it is presented in more detail in Section 2.5.5 as Steam Generator Overfill Sequence Number 1.

Overfill of a steam generator was not identified as a problem area in the H. B. Robinson Unit 2 FSAR analysis of an inadvertent opening of a main feedwater control valve, since SG overfill has not been included as one of the areas of concern in the FSAR Chapter 15 analyses. The FSAR analysis of an inadvertent opening of a main feedwater control valve looked primarily at the reactivity effects of overfeeding a SG and the possibility of exceeding DNB, but did not examine the effects of the transient on the steam generator water level. Therefore, even though the initial conditions for the FSAR analysis are conservative (especially where they have an affect on core reactivity during the transient), the FSAR analysis makes no mention of exceeding the high SG water level or the possibility of a SG overfill. The FSAR analysis of a main feedwater control valve opening should bound the Steam Generator Overfill Baseline Scenario (Number 1); however, a direct comparison is not possible to verify this assumption due to the lack of detail in the FSAR analysis, especially information concerning the SG water level.

The sequence of events for Steam Generator Overfill Baseline Scenario Number 1 is shown in Table C-36.

TABLE 36. SEQUENCE OF EVENTS FOR THE STEAM GENERATOR OVERFILL BASELINE SCENARIO (NUMBER 1)

Time (s)	Event
0.0	Transient initiated by opening SGA MFW control valve.
10.0	SGA MFW valve wide open.
22.0	Steam dump valve flow peaked at 39 kg/s (86 lbm/s).
35.7	MFW pump tripped on 75% SGA NR level.
36.1	SGA steam line check valve closed.
55.0	Steam dump valve closed.
127.0	Steam dump valve opened to control steam header pressure.
150.0	SGA boiler volumes reached saturation pressure and began voiding.
196.0	SGA steam line check valve reopened.
210.0	SGA NR level reached 96.6%.
240.0	Calculation stopped.

C.7.2 Steam Generator Overfill Scenario Number 2

The second step in the event scenario development process is to determine if any nonsafety grade systems were used to mitigate the baseline scenario, and if any nonsafety grade systems were used, to postulate their failure and deterministically analyze the resultant sequence.

The Steam Generator Overfill Baseline Scenario (Number 1) was not mitigated prior to exceeding the applicable Selection Criterion, therefore, it is not necessary to analyze the failure of nonsafety grade systems in conjunction with the baseline scenario in order to exceed the criterion. However, in order to maintain the same scenario development logic, aggravating system failures will be evaluated with the failure open of a feedwater control valve initiated from different initial plant conditions than used for the baseline scenario.

The Steam Generator Overfill Baseline Scenario (Number 1) and the FSAR analysis of an inadvertent opening of a feedwater control valve both took credit for the nonsafety grade steam generator high level trip to stop main feedwater flow into the affected steam generator. A failure mode that resulted in a continuation of main feedwater flow above the SG high level trip point (75% NR) was deterministically analyzed and resulted in exceeding Selection Criterion 7. A detailed discussion of this event is included in Section 2.5.6 as Steam Generator Overfill Sequence Number 2.

The Steam Generator Overfill Baseline Scenario (Number 1) did not take credit for the operation of any other nonsafety grade systems.

C.7.3 Steam Generator Overfill Scenario Number 3a

The third step in the event scenario development process is to examine the Steam Generator Overfill Baseline Scenario (Number 1) to determine if a single safety grade system failure was assumed. In this case, a single safety grade system failure had not been assumed. The selected suspect

systems list for a steam generator overfill was reviewed for the purpose of identifying safety grade system failures that would contribute to a steam generator overfill. Table C-37 shows the selected suspect systems for a steam generator overfill event. Of the systems listed as possible contributors to a steam generator overfill, four are safety grade systems: the steamline overpressure protection system, the main steam system (MSIVs), the auxiliary feedwater system, and the steam generator (tubes and tube sheet).

An inadvertent opening of an MSIV could cause an increase of steam flow which would cause level swell in the affected steam generator. During periods of normal plant operation an MSIV could not inadvertently open because it should not be closed. It is a violation of H. B. Robinson Unit 2 General Procedure-4 to not open all MSIVs during plant startup. It would involve an operator error for the plant to be at power with an MSIV closed. A failure closed and subsequent reopening of an MSIV is not considered since the failure closed could result in an SIAS, a reactor trip, and a turbine trip.

A steam generator tube rupture can result in overfill of the faulted steam generator. This failure mode is addressed as a separate accident category in Sections 2.5 and C.8 of this report.

Steam Generator Overfill Scenario Number 3a is initiated at 67% reactor power with rod control in manual and all other control systems operating in automatic. The scenario is initiated by two level instruments on one steam generator failing low. These failures will initiate auxiliary feedwater flow, which will continue for the duration of the transient, and also will result in a reactor trip. Failing the controlling SG level instrument low would result in the level controller starting to open the feedwater control valve, however, the reactor trip and turbine trip would result in a closure signal to the main feedwater control valve after 9.1 s.

TABLE C-37. SELECTED SUSPECT SYSTEMS FOR A STEAM GENERATOR OVERFILL EVENT

System	Failure Mode	Loss of Electrical Power or Air	Safety Grade	Postulated Effects
Control rod drive system	Inadvertent rod with-drawal		No	An inadvertentd withdrawal could contribute to a steam generator overfill by causing a power increase which causes steam generator level swell.
Feedwater and condensate system	High flow		No	A high flow rate or failure to trip when required could contribute to a steam generator overfill due to excessive coolant feed.
Steam line overpressure protection system	Inadvertent opening of a PORV or safety valve		Yes	An inadvertent steamline safety valve or PORV opening could contribute to a steam generator overfill by causing level swell.
Main steam system	Inadvertent MSIV opening		Yes	An inadvertent MSIV opening could contribute to a steam generator overfill by causing a high steam flow rate and level swell.
Turbine generator system	Inadvertent control valve opening		No	An inadvertent turbine control valve opening could contribute to a steam generator overfill by causing a high steam flow and level swell.
Auxiliary feedwater system	Inadvertent start	1	Yes	Inadvertent start of AFW pumps could contribute to a steam generator overfill by causing a high feedwater flow rate.
Steam generator	Tube rupture		Yes	A steam generator tube rupture could contribute to a steam generator overfill, however, it is treated as an independent event category and is presented separately in Sections 2.5 and C.8.
Steam generator blowdown system	No flow	1, 2	No	A low steam generator blowdown flow rate could contribute to an overfill by causing the steam generator feed rate to be greater than the fluid removal rate.
Auxiliary steam system	High flow		No	A high steam flow could contribute to a steam generator overfill by causing a level swell.

TABLE C-37. (continued)

System	Failure Mode	Loss of Electrical Power or Air	Safety Grade	Postulated Effects
Main condenser, evacuation, and circulating water systems	High flow circulating water or increased vacuum		No	Increase in circulating water flow or increased vacuum will result in increased steam flow which could cause level swell.
Steam dump system	Inadvertent valve opening		No	An inadvertent steam dump opening could cause a high steam flow rate and a steam generator level swell.

a. Loss of electrical power--1; Los. of air--2

The sequence of events for Steam Generator Overfill Scenario Number 3a is presented in Table C-38. With only the auxiliary feedwater pumps running after 13.6 s, the rate of level increase is only 1.2% NR level per minute, which would require over 42 minutes to exceed the steam generator high level setpoint of 75%. Therefore, there should be sufficient time for the operator to take action to mitigate the transients before the steam generators overfill.

C.7.3.1 Steam Generator Overfill Scenario Number 3b. A second safety grade system failure was evaluated in Steam Generator Overfill Scenario Number 3b. This scenario assumed the failure open of a steamline safety valve to aggravate a failure open of a main feedwater control valve. The transient was initiated from 67% reactor power with all control systems in automatic except for rod control.

The sequence of events for this scenario is presented in Table C-39. The failure of the main feedwater control valve increased feed flow to the affected steam generator and the increased steam flow due to the open safety valve caused level swell in the steam generator. The steam generator level increased until the SG high level setpoint was reached, at which time the MFW pumps were tripped and the control valve was closed. The steam generator level then rapidly dropped off and the calculation was stopped.

The calculation results for this transient showed a decrease in steam quality in the steam dome of the steam generator. However, the steam generator level never did exceed the steam generator high level setpoint of 75%, therefore, there was insufficient separator flooding to result in moisture carryover into the main steamline.

C.7.3.2 Steam Generator Overfill Scenario Number 3c. Since the failure open of a single steamline safety valve did not result in moisture carryover into the main steamline in Steam Generator Overfill Scenario Number 3b, Steam Generator Overfill Scenario Number 3c evaluated the case where the steamflow out of the steamline overpressure protection valves is

TABLE C-38. SEQUENCE OF EVENTS FOR STEAM GENERATOR OVERFILL SCENARIO NUMBER 3a

Time (s)	Event
0.0	Transient initiated by failing 2/3 SGA NR level instruments.
0.05	Reactor tripped on 1/3 NR levels < 15%.
	Motor-driven AFW pumps initiate flow to SGA.
0.1	Turbine tripped by reactor trip.
	All MFW valves began closing in response to change in SG setpoint level from 52% to 39%.
0.5	Turbine stop valves closed.
0.8	Pressurizer On-Off heaters actuated on low pressure.
2.0	SGA MFW valve began ramping open.
3.0	SGB and SGC MFW valves completely closed due to change in level setpoint and reduction in steam flow rates.
9.1	SGA MFW valve began closing due to combination of reactor trip and low T-ave (554 F).
13.6	Both MFW pumps tripped on low discharge flow.
14.0	SGA MFW valves completely closed.
34.7	SGB NR level decreased below 15%.
34.8	SGC NR level 15%.
35.3	Steam-driven AFW initiated to all three steam generators on 2/3 low-low SG NR levels (15%).
300.0	Stopped the calculation.

TABLE C-39. SEQUENCE OF EVENTS FOR STEAM GENERATOR OVERFILL SCENARIO NUMBER 3b

Time (s)	Event
0.0	Transient initiated by failing SGA controlling level tap to 0.0. One SGA safety valve was failed open.
2.0	Safety valve flow rate peaked at 175 lbm/s.
4.5	Safety valve flow rate stabilized at 155 lbm/s.
8.0	SGA main feedwater valve fully open. Feedwater flow had linearly increased over this period from an initial value of 558 lbm/s to 1345 lbm/s.
20.0	Turbine governor steam flow maintained at 67% load.
45.0	SGA NR level reached 75%.
	MFW pumps tripped
	MFW valves began closing
	Turbine tripped
	Reactor tripped
60.0	Closing the MFW valves and tripping the plant decreased the SGA NR level, and the calculation was subsequently terminated.

increased by failing a second valve open. This scenario was initiated from 67% reactor power with all control systems in the automatic mode except for rod control.

The sequence of events for Steam Generator Overfill Scenario Number 3c is provided in Table C-40. The results of this analysis closely parallel the results of overfill scenario number 3b. The decrease in steam quality in the steam generator steam dome occurs earlier in the transient and is slightly more severe, however, as in the previous transient the SG NR level does not exceed the 75% level and it is, thereby, concluded that no significant moisture carryover into the main steamline takes place during this event.

C.7.4 Steam Generator Overfill Scenario Number 4

The fourth step in the event scenario development process is to establish whether or not the worst case initial plant conditions were used in the H. B. Robinson Unit 2 FSAR analysis for a steam generator overfill. Reactor power was considered to be the one initial plant condition that could have a significant influence on a steam generator overfill event.

The initial plant conditions assumed for Steam Generator Overfill Scenario Number 4 are reactor power at 100% (instead of the ~5% power assumed in the baseline scenario) and all control systems in automatic except for the rod control system. The initiating event is a failure of the controlling steam generator water level instrument which results in a maximum feedwater flow rate to the affected SG.

Due to the small increase in feedwater flow that occurs when opening the feedwater control valve from its 100% position to the fully open position, compared with opening it from closed to fully open, the mismatch between feed flow and steam flow is much smaller for this transient than it

TABLE C-40. SEQUENCE OF EVENTS FOR STEAM GENERATOR OVERFILL SCENARIO NUMBER 3c

Time (s)	Event
0.0	Transient initiated by failing SGA controlling level tap to 0.0. One SGA safety valve and the SGA PORV were instantaneously failed wide open.
2.0	Safety valve and PORV flows stabilized at 172 lbm/s and 180 lbm/s, respectively.
7.0	SGA main feedwater valve fully open. Feedwater flow had linearly increased over this period from an initial value of 551 lbm/s to 1322 lbm/s.
20.0	Turbine governor steam flow maintained at 67% load.
49.2	SGA NR level reached 75%.
	MFW pumps tripped,
	MFW valves began closing,
	The turbine tripped, and
	The reactor tripped.
60.0	Closing the MFW valves and tripping the plant decreased the SGA NR level, and the calculation was subsequently terminated.

was for the Steam Generator Overfill Baseline Scenario (Number 1). Therefore, the rate of increase in the affected steam generator level is much slower than it was in the baseline scenario, however, there is a decrease in steam dome steam quality that occurs prior to the 75% NR MFW trip for this scenario, due to the higher initial power, that did not occur in the baseline scenario prior to the MFW trip. This decrease in steam quality did not result in moisture carryover into the main steamline since the SG NR level did not exceed the 75% high level setpoint at any time during the transient. A sequence of events for Steam Generator Overfill Scenario Number 4 is provided in Table C-41.

An evaluation of this scenario and the baseline scenario shows that the lower power level assumed for the baseline scenario is most severe for a high feedwater flow rate transient. The low initial power results in a greater feed flow-steam flow mismatch due to the MFW control valve failure, plus at low power levels the auxiliary feedwater flow will cause a steam generator overfill after the MFW has been tripped and the control valves closed. The flooding of the SG moisture separator will result in a decrease in steam quality at a lower SG water level if the transient is initiated at a high power level rather than a low power level. Also, there is another factor that would tend to favor higher initial powers than assumed for the baseline scenario, and that is the normal operating status of the MFW system during low power operation. At power levels below 10%, only one MFW pump would be in operation and the feedwater flow would be controlled by the bypass control valves. Therefore, it would not be likely for a main feedwater control valve to fail open; also the maximum flow would be restricted by the fact that only one of the MFW pumps would be operating. Taking all of these factors into consideration, it was decided to perform the remainder of the steam generator overfill calculations with an initial reactor power of 67%, which was the lowest of the previously developed steady state conditions where both MFW pumps would be operating and the flow would be controlled by the main feedwater control valves.

TABLE C-41. SEQUENCE OF EVENTS FOR STEAM GENERATOR OVERFILL SCENARIO NUMBER 4

Time (s)	Event
0.0	The controlling level instrument for SGA fails low.
4.0	The MFW control valve to SGA is completely open.
34.0	The pressurizer heaters are energized on low pressurizer pressure.
60.0	The SGA separator begins to flood resulting in a decrease in steam dome steam quality. Stopped the calculation.
~80.0	Extrapolated that the SGA high level trip setpoint would be reached resulting in a trip of the MFW pumps, isolation of the MFW, turbine trip, and reactor trip.

C.7.5 Steam Generator Overfill Scenario Number 5

The next step in the event scenario development process is to identify system failures from the selected suspect system list (see Table C-37) that would have the greatest effect in aggravating the baseline scenario. The effects of the aggravating system failures are divided into two categories based on the mechanism for causing an increase in steam generator level or carryover. The two overfill mechanisms are those failures that cause overfeed and those failures that cause level swell. The worst case overfeed is the initiating failure assumed for the baseline scenario, a failure full open of the main feedwater control valve. The systems from Table C-37 whose failure could cause level swell are: control rod drive system, steamline overpressure protection system, main steam system, turbine generator system, auxiliary steam system, main condenser systems, and the steam dump system. Many of these system failures have been assumed and analyzed previously during the scenario development process (see Table C-42). Table C-42 also provides the justification for not performing computer analyses to further evaluate some of the other system failures.

Steam Generator Overfill Scenario Number 5 assumed the worst case overfeed failure, which is failure full open of a main feedwater control valve, to initiate the transient. The initiating failure was aggravated by the worst two failures that could cause level swell; the failure fully open of the main turbine control valves and the failure full open of all steam dump valves. Due to uncertainty concerning the amount of effect that a rod control system failure would have on level swell, a third aggravating system failure of a continuous RCCA withdrawal was also assumed for this scenario. The scenario was initiated from 67% reactor power with all control systems operating in automatic except for rod control, which is in manual.

A sequence of events for this scenario is provided in Table C-43. The MFW flow rate increased at the start of the transient due to the increased steam flow to the main turbine and the steam dumps. At 5.8 s the MFW pumps

TABLE C-42. JUSTIFICATIONS FOR NOT UTILIZING AGGRAVATING SYSTEMS IN ADDITIONAL STEAM GENERATOR OVERFILL COMPUTER ANALYSES

Suspect Aggravating System	Failure Mode	Justification
Control rod drive system	Inadvertent rod withdrawal	This failure mode wa[illegible]ed in Steam Generator Overfill Scenario # [illegible] ion C.7.5.
Feedwater and condensate system	High flow	See Steam Generator Overfill Scenario Numbers 3a, 3b, 3c, 4, and 5 and Steam Generator Overfill Sequence Numbers 1 and 2 in Sections 2.5 and C.7.
Steamline overpressure system	Inadvertent opening of a PORV or safety valve	This failure mode was analyzed in Steam Generator Overfill Scenario Numbers 3b and 3c in Sections C.7.3.1 and C.7.3.2.
Main steam system	Inadvertent opening of an MSIV	For an MSIV to be closed during power operation would require violation of General Procedure 4, which would be an operator error and is, therefore, beyond the scope of this study. For an MSIV to open during shutdown would cause no problem since there would not be any steam flow paths open to draw off steam. A failure closed with a subsequent reopening of an MSIV was not analyzed, for the initial failure closed would result in an SIAS, reactor trip, turbine trip, etc.
Turbine generator systems	Inadvertent control valve opening	This failure mode was analyzed in Steam Generator overfill Scenario #5 in Section C.7.5.
Auxiliary feedwater system	Inadvertent start	An auxiliary feedwater start to initiate the transient was analyzed in Steam Generator Overfill Scenario Number 3a (Section C.7.3). An automatic start of auxiliary feedwater flow when the MFW pumps trip off at 75% NR is analyzed in Steam Generator Overfill Scenarios Numbers 1, 3b, 3c, 4, and 5.
Steam generator	Tube rupture	A steam generator tube rupture is analyzed in Sections 2.5.7 and 2.5.8 as Steam Generator Tube Rupture Sequences Numbers 1 and 2.

TABLE C-42. (continued)

Suspect Aggravating System	Failure Mode	Justification
Steam generator blowdown system	No flow	This failure mode would reduce the amount of secondary coolant being removed from the steam generator which would contribute to a steam generator overfill if the feedwater flow rate remains constant or increases. However, if the steam generator water level control system is functioning properly, this failure mode would have no effect on an overfill. The flow rate associated with the SG blowdown system would be very small when compared with the main feedwater flowrate, and while this failure might shorten the time required to reach the high level trip point, its effect on the overall transient would be insignificant.
Auxiliary steam system	High flow	This system failure could aggravate a steam generator overfill by causing level swell. However, the system piping size and configuration is such that the maximum flow rate would be bounded by the flowrate from either the main turbine or the steam dump, both of which are assumed to fail fully open in Steam Generator Overfill Scenario Number 5. This system failure is considered to be insignificant and is bounded by the failure of the main turbine control valves or the steam dump valves.
Main condenser, evacuation, and circulating water systems	High condenser vacuum or high circulating water flow	This system failure could aggravate a steam generator overfill since it could increase steam flow which would cause level swell. However, the amount that the condenser vacuum can possibly be increased is small, and that small vacuum increase would have an undiscernable affect on steam flow. Therefore, it is concluded that this failure mode is bounded by a failure open of a steamline safety valve as analyzed in Section C.7.3.2.
Steam dump system	Inadvertent opening of the steam dump valves	This failure mode was analyzed in Steam Generator Overfill Scenario Number 5 in Section C.7.5.

TABLE C-43. SEQUENCE OF EVENTS FOR STEAM GENERATOR OVERFILL SCENARIO NUMBER 5

Time (s)	Event
0.0	Transient initiated by failing the SGA controlling level tap to 0.0. Additionally, the turbine and steam dump valves were failed wide open (at their estimated maximum opening rates) and the most reactive control rod cluster was withdrawn at its highest rate (72 steps/min).
1.5	Steam dump valves fully opened.
5.8	Main feedwater pumps tripped on low suction pressure. Systems affected were:
	Turbine trip signal actuated (turbine not tripped in this scenario),
	Reactor trip signal actuated (maximum power reached was 1542 MW from an initial power of 1536 MW),
	MFW valves tripped (valves closed at maximum rate of 10%/sec) the maximum area of feedwater valves was 86.2%, and
	Motor-driven AFW initiated.
5.85	Condensate pumps tripped on low discharge pressure.
14.15	MSIVs tripped on 2/3 low Taves (543°F) and 2/3 steam/feed mismatch.
17.65	MSIVs completely closed.
18.0	SG levels reached 0.0 as levels responded to closing of the MSIVs.
	Steam-driven AFW started on 2/3 SG low levels (15%).
22.0	SG levels recovered to 30% then began decreasing as the secondaries cooled down, thereby collapsing the secondary voids.

were tripped off due to a low MFW pump suction pressure. The motor-driven AFW pumps started when the MFW pumps were tripped. Level swell due to the opening of the main turbine control valves and the steam dump valves caused an increase in the steam generator levels, however, the levels soon began to decrease since the turbine and steam dump valve failures were removing more water than was being added by the feedwater system. The MFW pump trip resulted in a turbine trip and a reactor trip. The turbine stop valves were not closed when the turbine trip was actuated because they were assumed to be failed open. However, all steam flow was stopped at 17.6 s when the MSIVs were closed. Once the MFW pumps were tripped and the MSIVs were closed, there were no mechanisms available to cause any rapid changes in the SG water level and the calculation was stopped.

The analysis results indicated that there was a decrease in the steam dome steam quality due to partial flooding of the moisture separator, however, the NR levels for the steam generators did not exceed 62% during the transient; it is, therefore, concluded that moisture carryover would not enter the main steamlines in Steam Generator Overfill Scenario Number 5.

C.7.6 Systems Susceptible to Loss of Electrical Power or Loss of Air

The final step in the event scenario development process is to analyze those systems dependent on electrical power or air. There are two of the selected suspect systems that, upon a loss of electrical power or air, transfer to their failure mode of concern as identified in Table C-37. These failure modes that could potentially create a steam generator overfill event have either been previously analyzed or are bounded by other scenario analyses. Table C-42 shows the applicable scenarios that have been developed and analyzed for these systems or provides the justification why further scenario development and deterministic analysis is not necessary.

C.7.7 Summary of Steam Generator Overfill Scenarios

One insight that was gained from this evaluation is that steam generator level swell, due to increased steam flow, can cause partial flooding of the moisture separator which will cause a reduction of the steam quality in the steam generator steam dome. However, swell did not cause any large scale carryover of moisture into the steamline because the steam generator level did not exceed the SG high level setpoint of 75% and the high steam flow often exceeded the feedwater flow rate which resulted in a reduction in the SG level. Overfeed of the steam generators was only shown to be a problem if the steam generator high level trip of the MFW system was rendered inoperable to permit continued operation of the MFW pumps, or when the AFW system caused a SG overfill (this only occurred at low power levels) after the MFW system was tripped off at 75% NR level.

The two system failures that did result in exceeding Selection Criterion 7 are discussed in greater detail in Section 2.5 of this report. Section 2.5.5 addresses the overfill by the AFW system at low power and Section 2.5.6 discusses the overfill due to the failure of the high level trip shutoff of the MFW system flow.

C.8 Steam Generator Tube Rupture Scenarios

The next event evaluated was a steam generator tube rupture. The main focus of the study for this event was system failures that could aggravate a steam generator tube rupture such that the accident results would exceed those identified in the H. B. Robinson FSAR analysis. The specific parameters of concern for this accident are break flow (flow from the RCS to the secondary), and flow from the secondary system to atmosphere. Both of these parameters have a direct affect on the amount of radioactive isotopes that could be released to the atmosphere which in turn affects the offsite release activity level.

An evaluation of a steam generator tube rupture did not reveal any system failures that could initiate the tube rupture. The basis for this conclusion is that the prefabrication test pressure for the steam generator tubes was 7000 psi and the calculated bursting pressure is in excess of 11,100 psi, based on ultimate strength at design temperature. These pressures are several factors (4.5 and 7.3, respectively) greater than 1530 psi, which is the approximate pressure on the tube wall at the maximum operating internal pressure. Therefore, a tube rupture was assumed as the initiating event for the tube rupture scenarios since no failures were identified that could cause the rupture to occur.

Steam generator tube rupture is not evaluated as a separate accident classification in the H. B. Robinson Unit 2 FSAR. It is classified as a decrease in reactor coolant inventory and is evaluated in Section 15.6 of the H. B. Robinson FSAR. As a decrease in inventory, tube rupture is bounded by the rupture of both small and large pipes in the RCS. However, due to the fact that a tube rupture not only affects a decrease in inventory, but also can result in a steam generator overfill, a RCS overcool, and a direct discharge of radioactive coolant to the atmosphere; it was decided to treat it as a separate event. The main focus of this evaluation will be on the release to atmosphere of radioactive coolant. The steam generator tube rupture accident analysis from the FSAR (Section 15.6.3) is utilized as the basis for the scenario development and analysis process that follows. Selected sections of that FSAR analysis are presented below:

> The event examined is a complete steam generator (SG) tube break adjacent to the tube sheet, since a minor leak may not necessitate immediate action, depending on the particular circumstances. If a tube breaks, reactor coolant would discharge into the secondary system. Since the reactor coolant is radioactive, methods of operation to limit uncontrolled condensate release have to be considered.

Once the reactor coolant system pressure is below the SG design pressure, the faulty SG will be isolated by stopping its main feedwater and closing the main steam isolation and bypass valves. This will remove the possibility of uncontrolled leakage.

The following sequence of events is initiated by a tube rupture:

1. Rapidly falling pressure in the pressurizer will initiate a safety injection signal, tripping the unit. The safety injection signal automatically terminates normal feedwater and initiates auxiliary feedwater. While not necessary for protection, there is sufficient capacity in the secondary system to contain, in a controlled manner, any leakage that might pass from the primary system to the secondary system, should no action be taken to isolate the leaks.

2. The SG liquid monitor and the air vacuum pump radiation monitor will alarm, indicating the passage of primary fluid into the secondary system. The air vacuum pump discharge is automatically diverted back to the plant vent within a few seconds.

3. The unit trip will automatically shut off steam flow through the turbine and will open the steam bypass valves and bypass steam to the condenser.

4. In the unlikely event of a concurrent loss of power, the loss of circulating water through the condenser would eventually result in loss of condenser vacuum and valves in the condenser bypass lines would automatically close to protect the condenser, thereby causing steam relief to be to the atmosphere.

5. Cooldown procedures are followed which entail:

   a. Boration by the high head safety injection pumps

   b. Regulating pressurizer level with spray or relief valves

   c. Reduce system temperature and pressure using steam dump, and

   d. Condenser relief (if available) or atmospheric relief in order to reduce the reactor coolant temperature.

6. Isolation of the faulty SG is achieved by:

   a. Stopping the auxiliary feedwater flow to the affected SG

   b. Isolating main feedwater to the affected SG, and

   c. Closing the steam line stop valve connected to the affected SG (determined by SG liquid sample activity monitor) and blocking the atmospheric relief.

7. Ordinarily this would end the leakage during the interval while cooldown is continuing by steam bypass from the intact SG. Should the faulty SG outlet valve not close, then the main steamline bypass valves would be closed and atmospheric relief from the intact SG would be used for plant cooldown.

8. After the residual heat removal system is in operation, the condensate accumulated in the secondary system can be examined. If the radioactivity level is in excess of that allowed, the condensate can be processed through the waste disposal system.

The faulty unit will be isolated by a steam line isolation valve. This can be accomplished in approximately 30 min. and will terminate the mass flow into the secondary system and steam relief from the faulty SG.

With power available to the circulating water pumps, the steam is bypassed to the condenser.

With a concurrent loss of power, a portion of the RCS activity is released to the atmosphere in steam relief during the 30 min. to isolate the faulty SG.

All of the noble gas activity contained in the portion of reactor coolant discharged into the SG during the 30 min. to isolate is assumed to be released to atmosphere.

The iodine transferred into the SG is assumed to partition between the liquid and vapor phases of the SG and the portion contained in the steam relief is assumed released to atmosphere. A distribution factor of 4×10^{-3} curies/cm^3 steam/curies/cm^3 water has been selected as being representative of the pH and pressure conditions within the SG.

During the 30 min. period needed to isolate the faulty SG, 70,000 lb of reactor coolant are discharged into the SG and 57,000 lb of steam are relieved to atmosphere. Based on a RCS activity concentration corresponding to 1 percent defective fuel, the noble gas activity release to atmosphere is 9,500 equivalent Curies Xe-133. The corresponding iodine activity discharge into the SG is 78 Curies equivalent I-131, of which 3.9 Curies are released to atmosphere.

The resultant site boundary dose is less than 0.3 rem whole body and less than 2 rem to the thyroid, using the two hour meteorological dispersion factor.

The discharge rate required to lift a secondary safety valve is about 15 times the rate from a single severed SG tube.

These conclusions are based on single-failure mode performance of the core cooling system. Cladding damage is prevented in those cases where the top of the core does not become uncovered.

The discharge rate required to cause the top of the core to become uncovered is 18 to 40 times the rate from a single severed tube.

The incredibility of multiple simultaneous tube failures is supported by the following reasoning:

1. At the maximum operating internal pressure, the tube wall sees only about 1530 psi, compared with a calculated bursting pressure in excess of 11,100 psi, based on ultimate strength at design temperature (factor of 7.3); and compared with a prefabrication test pressure of 7,000 psi (factor of 4.5).

2. The above margin applies to the longitudinal failure mode, induced by hoop stress. This failure mode is the least likely to cause propagation of failure tube-to-tube. An additional factor of two applied to ultimate pressure strength in the axial direction tending to resist double-ended failure (total factor of 14.6).

3. Failures induced by fretting, corrosion, erosion or fatigue, in addition to being rendered extremely improbable by design, are of such a nature as to produce tell-tale leakage in substantial quantity, while ample metal remains to prevent severance of the tube (a small fraction of the original tube wall section, as indicated by the margin derived in Item (2) above). Thus, it is virtually certain that any incipient failures that would develop to the point

of severe leakage requiring a shutdown for repair would happen long before the large safety margin in pressure strength is lost.

Insufficient detail was provided in the H. B. Robinson FSAR to develop a sequence of events for the steam generator tube rupture event.

C.8.1 Steam Generator Tube Rupture Baseline Scenario (Number 1)

The first step in the steam generator tube rupture scenario development process is to deterministically examine the effects of a steam generator tube rupture with a loss of offsite power. The Steam Generator Tube Rupture Baseline Scenario is the same as the SG tube rupture accident presented in Chapter 15 of the H. B. Robinson FSAR. As explained in the following sections, the initial conditions and aggravating system failures assumed in the FSAR analysis are conservative and bound all system failures except a failure in the steam line pressure protection system. It was, therefore, decided that it was not necessary to repeat the deterministic analysis of SG tube rupture with loss of offsite power. For this step, the SG tube rupture with loss of offsite power presented in Chapter 15 of the H. B. Robinson FSAR was analyzed to determine the failures assumed and the mitigative systems that operated.

C.8.2 System Generator Tube Rupture Scenario Number 2

The second step in the event scenario development process is to determine if any nonsafety grade systems were used to mitigate the baseline scenario, and if any nonsafety grade systems were used, to postulate their failure and deterministically analyze the resultant sequence. The assumed loss of offsite power would disable most nonsafety grade systems (i.e.: steam dump system), so they would not be available to help mitigate this event. However, several nonsafety grade components were apparently used in the FSAR analysis to cooldown and depressurize the RCS and to isolate the faulty SG, thereby stopping break flow within 30 min. Even though the above mentioned use of nonsafety grade equipment is nonconservative and

results in an earlier equalization of pressure between the RCS and the faulted SG, it is our judgement that the effects of failing these nonsafety grade systems would be bounded by the aggravating failure open of a steam line PORV during a tube rupture with loss of offsite power. The basis for this judgement is that the net effect of failing the nonsafety grade systems used in the FSAR analysis would be to lengthen the time required to cool and depressurize the RCS and to equalize the pressures across the break to stop break flow, and a failed open steam line PORV on the faulty steam generator would have the same effect of lengthening the time required to equalize pressures to stop break flow with the added factor of providing a direct flow path to the atmosphere for the radioactive coolant in the steam generator. Since the failure of the nonsafety grade systems used in the baseline scenario are bounded by failure open of a steamline PORV during a tube rupture, the nonsafety grade system failures are not deterministically analyzed.

C.8.3 Steam Generator Tube Rupture Scenario Number 3

The third step in the event scenario development process is to examine the Steam Generator Tube Rupture Baseline Scenario (Number 1) to determine if a single safety grade system failure was assumed. Although it is not specifically stated in the FSAR analysis, based on what has been identified by other Westinghouse PWRs, the safety grade system failure assumed for a tube rupture with loss of offsite power is a failure of one train of ECCS.

The selected suspect systems list for steam generator tube rupture (Table C-44) was reviewed for the purpose of identifying safety grade system failures that would contribute to the severity of a steam generator tube rupture event. Of the systems listed, four are safety grade systems: The steamline overpressure protection system, the main steam system (MSIVs), the auxiliary feedwater system, and the steam generator system (tubes and tube sheet).

A premature opening or failure open of a steamline safety valve on the faulted SG would aggravate the baseline scenario and result in an increase in the release of radioactive coolant to the atmosphere. This system

TABLE C-44. SELECTED SUSPECT SYSTEMS FOR A STEAM GENERATOR TUBE RUPTURE EVENT

System	Failure Mode	Loss of Electrical Power or Air	Safety Grade	Postulated Effects
Reactor coolant system and pumps	No flow	1	No	A loss of reactor coolant pump flow would cause a decrease in heat transfer from the reactor coolant system which could cause an increase in pressure. An increase in pressure could cause an increase in inventory loss rate.
Chemical and volume control system	High charging flow or no letdown flow	1, 2	No	A high charging or low letdown flow rate could contribute to a tube-rupture transient by injecting coolant to the RCS which would keep RCS pressure high and increase break flow.
Pressurizer pressure control system	Controlling pressure high	2	No	A high pressure condition could contribute to a tube rupture transient by causing an increase in coolant loss rate.
Control rod drive system	Rod withdrawal or ejection		No	An inadvertent rod withdrawal could contribute to a tube rupture transient by adding heat to the reactor coolant system which would keep pressure high and increase break flow. A rod ejection was rejected as it would cause a reactor coolant system break which would cause a faster depressurization and make the transient less severe.
Feedwater and condensate system	High flow		No	A high flow to the affected steam generator could contribute to a tube rupture transient by filling the steam generator liquid full which could result in a higher release of particulated material to the atmosphere through an open PORV or safety valve.
	Low flow	1, 2		Low flow rate to the unaffected steam generators could contribute to a tube rupture transient by reducing the heat transfer from the reactor coolant system which causes RCS pressure to remain high and the break flow to be high.

TABLE C-44. (continued)

System	Failure Mode	Loss of Electrical Power or Air	Safety Grade	Postulated Effects
Steamline overpressure protection system	Inadvertent PORV or safety valve opening		Yes	An inadvertent valve opening on the affected steam generator could contribute to a tube rupture transient by causing the differential pressure between the reactor coolant system and secondary to remain high which increases break flow.
Main steam system	Inadvertent MSIV opening		Yes	An inadvertent MSIV opening on the affected steam generator could contribute to a tube rupture transient by causing increased break flow due to the steam pressure drop from continued breakflow.
	Inadvertent MSIV closure	1		An inadvertent MSIV closure on the unaffected steam generator could contribute to a tube rupture transient as the valve closure causes a reduction in heat transfer from the reactor coolant system which increases break flow from a slower pressure decrease.
Turbine generator system	Inadvertent turbine control valve closure	1	No	An inadvertent valve closure could contribute to a tube rupture transient by causing a reduction in heat transfer from the reactor coolant system which increases break flow from a slower depressurization.
Auxiliary feedwater systems	Inadvertent start	1	Yes	Inadvertent feed flow to the affected steam generator could contribute to a tube rupture transient by causing the steam generator to fill liquid full which could cause the release of particulated materials to the atmosphere through a PORV or safety valve.
Steam generator	Tube rupture		Yes	A tube rupture is the subject of this evaluation.
Steam generator blowdown system	High flow		No	A high flow could contribute to a tube rupture transient by causing a decrease pressure in the affected steam generator which could cause increased break flow.

TABLE C-44. (continued)

System	Failure Mode	Loss of Electrical Power or Air	Safety Grade	Postulated Effects
Steam generator sampling system	High flow		No	A high flow could contribute to a tube rupture transient by causing a decrease pressure in the affected steam generator which could cause increased break flow.
Auxiliary steam system	No flow	1, 2	No	A loss of steam flow could result in the loss of condenser vacuum which reduces the heat transfer from the reactor coolant system and an increase in break flow.
Main condenser, evacuation and circulating water systems	No circulating water flow or a loss of vacuum	1	No	No circulating water flow or a loss of condenser vacuum could contribute to a tube rupture transient by decreasing the heat transfer from the reactor coolant system which could increase break flow.
Steam dump system	Failure to operate	1, 2	No	A failure of the steam dump to operate could contribute to a tube rupture transient by reducing the heat transfer from the reactor coolant system which could increase break flow.

a. Loss of electrical power--1; Loss of air--2

failure was not used as an aggravator in a deterministic analysis since a failure open of a steamline PORV, which is a nonsafety grade valve, was analyzed with a tube rupture and loss of offsite power. The failure open of the PORV was chosen for the analysis since it did not involve a safety grade failure and, like the safety valves, there are no isolation valves that can be closed to stop the flow to the atmosphere.

There are two failure modes of concern for the MSIVs. The first involves the faulted SG where a failure open of the MSIV would prevent isolation of the steam generator, this could lengthen the time required to stop break flow. This failure mode would have little effect on the baseline scenario because the loss of offsite power would result in the isolation of the main turbines and the steam dumps which would essentially isolate the main steam header. In this situation the steamline PORVs would be opened on the nonfaulted SGs to cool the RCS, this would reduce the pressure in the nonfaulted SGs causing the associated steamline check valves to close. If this failure mode occurred to aggravate a tube rupture when offsite power was not lost, as stated in the H. B. Robinson FSAR analysis, to isolate the faulted SG it would be necessary for the operators to stop steam dump flow and cool the RCS using the steamline PORVs on the nonfaulted SGs. It is concluded that this failure mode would have an insignificant effect on a tube rupture event and would be bounded by a failure open of a steamline PORV or safety.

The second failure mode for the main steam system involves a failure closed of an MSIV on one of the nonfaulted SGs. For the baseline scenario where a loss of offsite power precludes use of the steam dumps to cool the RCS, this failure mode would have no effect on the analysis. For a tube rupture event where offsite power is available, this failure would have little effect on the accident because there would still be one SG that could cooldown the RCS using the steam dumps, and the steamline PORV on the other nonfaulted SG could be used to augment the cooldown rate, if necessary. It is therefore, concluded that this MSIV failure mode is insignificant and is bounded by the failure open of a steamline PORV or safety valve.

Inadvertent start of the auxiliary feedwater system could aggravate a steam generator tube rupture event by increasing the level in the faulted steam generator, however, this should not occur if the steam generator water level control system is functioning properly. Even if the level control system is not operating, AFW flow would go into the SG with the lowest pressure, which would probably not be the faulted SG due to the inflow of reactor coolant through the break. When the loss of offsite power occurred at the start of the baseline scenario, the MFW pumps were deenergized which resulted in a start of the AFW pumps. Even if offsite power remains available the effects, if any, due to a spurious start of the AFW pumps would be short lived. This system failure is judged to be insignificant and is bounded by the high MFW flow rate failure analyzed in Steam Generator Tube Rupture Sequence Number 2 (Section 2.5.8).

The last safety grade system failure mode from the suspect system list is the steam generator tube rupture which is the assumed initiator for all of the events analyzed in this section.

C.8.4 Steam Generator Tube Rupture Scenario Number 4

The fourth step in the event scenario development process was to establish whether or not the worst case initial plant conditions were used in the H. B. Robinson FSAR analysis of the steam generator tube rupture event.

The H. B. Robinson FSAR analysis of a steam generator tube rupture does not provide any initial plant conditions. It is assumed that conservative initial conditions were utilized by the licensee when performing the calculations. No deterministic analyses were performed for this study to determine the worst case initial conditions for a SG tube rupture. Based on the results of computer calculations of steam generator tube rupture scenarios perform for the pressurized thermal shock (PTS) study,[17] it appears that tube rupture calculations are more severe for steam generator overfill and RCS overcool when initiated from hot shutdown conditions, however, they appear to be more severe in regards to the

release of radioactive coolant to the atmosphere when initiated from high reactor powers. Since radioactive coolant release to atmosphere was our primary concern, high initial power levels (102% reactor power) were used for the tube rupture calculations performed for this study.

C.8.5 Steam Generator Tube Rupture Scenario Number 5

The purpose of this step is to identify system failures from the selected suspect system list (Table C-44) that would have the greatest effect in aggravating the baseline scenario, or in other words, produce the worst case scenario in an attempt to exceed Selection Criteria 8.

The loss of offsite power assumed for the Steam Generator Tube Rupture Baseline Scenario resulted in the occurrence of many of the failure modes that are identified on the selected suspect system list. The affected systems and their failure modes are presented below:

Reactor coolant system and pumps - no flow

Feedwater and condensate system - no flow

Turbine generator system - turbine control valve closure

Auxiliary feedwater system - inadvertent start (due to loss of MFW pumps)

Auxiliary steam system - no flow

Main condenser and support systems - no vacuum

Steam dump system - failure to operate (due to loss of condenser vacuum).

A more detailed discussion for each system is provided in Table C-45, Justification For Not Utilizing Aggravating Systems In Additional Steam Generator Tube Rupture Computer Analysis.

One of the suspect system failure modes that is not affected by a loss of offsite power is a failure open of a steamline PORV or safety valve. This failure mode was analyzed and was found to exceed Selection Criteria 1, 7, and 8. A discussion of a failure open of a steamline PORV as an aggravating failure to the Steam Generator Tube Rupture Baseline Scenario is presented as Steam Generator Tube Rupture Sequence Number 1 in Section 2.5.7.

Another aggravating system failure that was analyzed for this study is a high feedwater flow rate to the faulted SG. This failure was used to aggravate a steam generator tube rupture event where offsite power remains available. A second aggravating failure assumed for that analysis is a failure open of the faulted SG PORV. The discussion of this sequence is presented in Section 2.5.8 as Steam Generator Tube Rupture Sequence Number 2.

The remainder of the suspect system failures are either judged to be insignificant or are bounded by failures assumed in one or more of the analyses discussed above. The justifications for not utilizing these failures in further computer analyses are presented Table C-45.

C.8.6 Systems Susceptible to Loss of Electrical Power or Loss of Air

The final step in the event scenario development process is to analyze those systems dependent on electrical power or air. There are several of the selected suspect systems that, upon a loss of electrical power, transfer to their failure mode of concern as identified in Table 44. Steam Generator Tube Rupture Sequence Number 1 and the H. B. Robinson FSAR SG tube rupture analysis assume a loss of electrical power. As discussed above in Section C.8.5 and in Table C-45, the effects of a loss of electrical power have been analyzed and these effects need not be further evaluated.

TABLE C-45. JUSTIFICATIONS FOR NOT UTILIZING AGGRAVATING SYSTEMS IN ADDITIONAL STEAM GENERATOR TUBE RUPTURE COMPUTER ANALYSES

Suspect Aggravating System	Failure Mode	Justification
Reactor coolant system and pumps	No flow	See Steam Generator Tube Rupture Sequence Number 1 (Section 2.5.7) and the H. B. Robinson FSAR SG tube rupture analysis. In both of these cases a loss of offsite power is assumed which would result in deenergizing the RCPs.
Chemical and volume control system	High charging flow or low letdown	A steam generator tube rupture results in a decrease in pressurizer level due to the flow from the RCS into the secondary. Normal operation of the pressurizer level control system would call for an increase in charging flow to try and maintain the pressurizer level. Normal operation of this system is assumed in Steam Generator Tube Rupture Sequence Number 1 (Section 2.5.7), therefore, full charging flow was analyzed in this sequence. An SIAS would result in an automatic isolation of the letdown flow path and all of the analyzed SG tube rupture events resulted in an SIAS from low pressurizer pressure.
Pressurizer pressure	Controls pressure	See Steam Generator Tube Rupture Sequence Numbers 1 and 2 (Sections 2.5.7 and 2.5.8) where the initial pressure was assumed to be 2280 psia, 30 psi above nominal. A tube rupture will cause a rapid decrease in pressurizer pressure which will result in energizing the pressurizer heaters (if power is available), however, the heaters would be tripped off on low pressurizer level early in the sequence and would have little or no effect on the accident.
Control rod drive system	Rod withdrawal	A control rod withdrawal could increase reactor power which would result in higher RCS temperatures and pressures. The rate of increase in power is slow, even when the rod is withdrawn at maximum speed, and a reactor trip is actuated early in the transient, therefore, the effects of this failure would be insignificant and would be bounded by the reactivity effects of full feedwater flow postulated in Steam Generator Tube Rupture Sequence Number 2 (Section 2.5.8). A reactor trip is actuated immediately for the events where loss of offsite power is assumed.
Feedwater and condensate system	High flow to faulted steam generator	See Steam Generator Tube Rupture Sequence Number 2 (Section 2.5.8).
	No flow to nonfaulted steam generators	See Steam Generator Tube Rupture Sequence Number 1 (Section 2.5.7) where loss of offsite power would deenergize the MFW pumps.

TABLE C-45. (continued)

Suspect Aggravating System	Failure Mode	Justification
Steamline overpressure protection system	Inadvertent opening of a steamline safety valve or PORV	See Steam Generator Tube Rupture Sequence Numbers 1 and 2 (Sections 2.5.7 and 2.5.8).
Main steam system	Inadvertent opening of the MSIV on the faulted SG	This failure could lengthen the time required to cooldown the RCS and equalize the pressures across the break. For the events where a loss of offsite power is assumed, this failure would have no effect since all of the systems that use steam flow (main turbine, steam dumps, and auxiliary steam) would be isolated by the loss of power or loss of condenser vacuum and the RCS cooldown would be achieved by venting steam to atmosphere through the nonfaulted SG PORVs; this would result in a higher pressure in the faulted SG which would close the nonfaulted SG steamline check valves. If offsite power is available, the operators could switch from the steam dumps to the nonfaulted SG PORVs to cool the RCS and the faulted SG would be isolated from the nonfaulted SG by closure of the steamline check valves as mentioned above.
	Inadvertent closure of the MSIV on a non-faulted SG.	This failure could lengthen the time required to cooldown the RCS. For scenarios where loss of offsite power is assumed, this failure would have no effect because the cooldown would be performed using the steamline PORVs to dump steam to the atmosphere instead of the condenser. If offsite power is available, this failure would result in the loss of heat removal from one of the nonfaulted SGs until operator action is taken to open the PORV for that SG. Since the RCPs would be operating, the heat removal capability of the remaining nonfaulted SG should be sufficient to cool the RCS at the technical specification cooldown rate limit. The overall effect of these failures would be insignificant in aggravating a SG tube rupture event.
Turbine generator system	Closure of the turbine control valve	See Steam Generator Tube Rupture Sequence Number 1 (Section 2.5.7) and the H. B. Robinson FSAR SG tube rupture analysis where the loss of offsite power results in an immediate turbine trip.

TABLE C-45. (continued)

Suspect Aggravating System	Failure Mode	Justification
Auxiliary feedwater system	Inadvertent start	For scenarios that assume a loss of offsite power, the AFW pumps start as they are intended to upon loss of power to the MFW pumps. If offsite power is available, the SG water level control system should control the level in the affected SG which would result in this failure having no effect on the accident. Also AFW flow will go to the SG with the lowest pressure, and the faulted SG pressure will probably be higher than the nonfaulted which will preclude any flow to the faulted SG. This failure mode is insignificant and is bounded by high MFW flow rate in Steam Generator Tube Rupture Sequence Number 2 (Section 2.5.8).
Steam generator blowdown system	High flow from the faulted SG	This failure could result in a decrease in pressure in the faulted SG which would increase the time required to equalize the pressure across the break. The flow rate in this system is small in comparison to the steamline PORV flow rate and this system would be isolated early in the accident by either a loss of offsite power or an SIAS. Therefore, this failure mode is insignificant and is bounded by a failure open of a steamline PORV (see Steam Generator Tube Rupture Sequence Number 1 and 2, Sections 2.5.7 and 2.5.8).
Steam generator sampling system	High flow from the faulted SG	This failure could result in a decrease in pressure in the faulted SG which would increase the time required to equalize the pressure across the break. The flow rate in this system is small in comparison to the steamline PORV flow rate and this system would be isolated early in the accident by either a loss of offsite power or an SIAS. Therefore, this failure mode is insignificant and is bounded by a failure open of a steamline PORV (see Steam Generator Tube Rupture Sequence Number 1 and 2, Sections 2.5.7 and 2.5.8).
Auxiliary steam system	No flow	See Steam Generator Tube Rupture Sequence Number 1 (Section 2.5.7) and the H. B. Robinson FSAR SG tube rupture analysis. In both cases the assumed loss of offsite power would result in a turbine trip, reactor trip, loss of condenser vacuum and isolation of the auxiliary steam system.

TABLE C-45. (continued)

Suspect Aggravating System	Failure Mode	Justification
Main condenser, evacuation, and circulating water systems	Loss of vacuum or no circulating water flow	See Steam Generator Tube Rupture Sequence Number 1 (Section 2.5.7) and the H. B. Robinson FSAR SG tube rupture analysis. In both cases the assumed loss of offsite power would result in deenergizing the condenser evacuation pumps and condenser circulating water pumps which would result in a loss of condenser vacuum.
Steam dump system	Failure to operate	See Steam Generator Tube Rupture Sequence Number 1 (Section 2.5.7) and the H. B. Robinson FSAR SG tube rupture analysis. In both cases the assumed loss of offsite power would result in a loss of condenser vacuum which would disable the steam dump system.

A loss of air affects several of the suspect systems as identified in Table 44. In all cases except for the pressurizer pressure control system, the applicable systems are also affected by loss of electrical power, which causes the same failures to occur that would result from a loss of air, and has already been analyzed as discussed above. A high initial RCS pressure was assumed for Steam Generator Tube Rupture Sequences Numbers 1 and 2. Therefore, the effects of a loss of air have been analyzed for all of the identified suspect systems for a SG tube rupture event.

C.8.7 Summary of Steam Generator Tube Rupture Scenarios

The analysis of a steam generator tube rupture in the H. B. Robinson FSAR bounds all of the selected suspect system failures except a failure open of a steamline PORV or safety valve and a high feedwater flowrate to the faulted steam generator. These system failures have been deterministically analyzed (Sections 2.5.7 and 2.5.8) and have been found to exceed Selection Criteria 1, 7, and 8. The failure open of a steamline PORV or safety results in a direct flow path from the RCS to the atmosphere and also results in a lower secondary pressure which would lengthen the time required to equalize the pressure across the break to stop break flow.

C.9 REFERENCES

1. H. B. Robinson Steam Electric Plant Unit No. 2 Updated Final Safety Analysis Report, Docket Number 50-261, Carolina Power and Light Company, May 9, 1980.

2. H. B. Robinson Steam Electric Plant Unit Number 2 Technical Specifications, Appendix A to Facility Operating License Number DPR-23, Carolina Power and Light Company.

3. Time Response Design Criteria for Safety-Related Operator Actions, Draft, ANSI N660, Revision 2, March 1981.

4. ASME Boiler and Pressure Vessel Code, Section III, Article NM-7000, "Protection Against Overpressure," American Society of Mechanical Engineers.

5. Code of Federal Regulations, Energy, 10 CFR 50, Appendix G, January 1981.

6. Code of Federal Regulations, Energy, 10 CFR 100, January 1981.

7. W. R. Cadwell, PDQ-7 Reference Manual, WAPD-TM-678, Westinghouse Electric Corporation, January 1965.

8. J. N. Morgan, XTRAN-PWR: A Computer Code for the Calculation of Rapid Transients in Pressurized Water Reactors with Moderator and Fuel Temperature Feedback, XN-CC-32, Exxon Nuclear Company, August 1975.

9. F. D. Lang et al., XTHETA: Multi-Node Heatup Code for Single Channel Transient Analysis, XN-74-21, Revision 2, Exxon Nuclear Company, April 1975.

10. H. B. Robinson Steam Electric Plant Unit No. 2 Updated Final Safety Analysis Report, Section 15.3.1.2, Docket Number 50-261, Carolina Power and Light Company, May 9, 1980.

11. R. Salvatori, Fuel Densification, H. B. Robinson Steam Electric Plant, WCAP-8114, April 1973.

12. IEEE Standard Guide for Protection Systems for Nuclear Power Generating Stations, ANSI/IEEE Std. 279-1971, American National Standards Institute, April 1972.

13. Description of the Exxon Nuclear Plant Transient Simulation Model for Pressurized Water Reactors (PTS-PWR), XN-74-5, Revision 1, May 1975 (Proprietary).

14. D. E. Baxter et al., H. B. Robinson Steam Generator Overfill Transient Failure Mode and Effects Analysis and Rejected Systems Justification Report, EGG-EA-6282, Preliminary, EG&G Idaho, Inc., May 1983.

15. D. E. Baxter and S. J. Bruske, H. B. Robinson Overcooling Transient Failure Mode and Effects Analysis and Rejected Systems Justification Report, EGG-EA-6297, Preliminary, EG&G Idaho, Inc., May 1983.

16. D. E. Baxter et al., Westinghouse 3-Loop Other Transients Failure Mode and Effects Analysis and Rejected Systems Justification Report, EGG-EA-6468, Preliminary, EG&G Idaho, Inc., December 1983.

17. C. D. Fletcher et al., RELAP5 Thermal-Hydraulic Analyses of Pressurized Thermal Shock Sequences for the H. B. Robinson Unit 2, Pressurized Water Reactor, EGG-SAAM-6476, EG&G Idaho, Inc., December 1983.

EG&G Idaho

NOTEGRAM

FORM EG&G-460 A
(Rev. 04-79)

Date August 6, 1984

To John E. Hord
Westinghouse Electric Corp.
Water Reactor Division

From Stan Bruske/Clair Ransom CBR

Org. EG&G Idaho, Inc.
NRC Licensing Support Section

Address Pittsburgh, Pennsylvania

Address Idaho Falls, Idaho

PROPOSAL TO PERFORM GENERIC EVALUATION - MC-35-84

Attached is the main body of our report dealing with the effects of control system failures on transients and accidents at the H. B. Robinson Steam Electric Plant. This report contains a discussion of the methodology utilized in the study along with the event scenario computer analysis and effects for the Group 2 Transients.

We will send you the scenario computer analysis and effects report sections for several of the Group 1 Transients during the week of August 5, 1984. The remainder of the Group 1 report sections will be mailed to WEC as soon as they are completed.

If you have any questions regarding these materials or this task, please call Stan Bruske at 208-526-9345, (FTS 583-9345) or Clair Ransom at 208-526-4362 (FTS 583-4362).

jm

Attachment:
As Stated

cc: P. E. Litteneker - DOE
R. E. Lyon
C. F. Obenchain
E. W. Roberts
A. J. Szukiewicz - NRC

EG&G Idaho

NOTEGRAM

FORM EG&G-460 A
(Rev. 04-79)

Date August 10, 1984

To John E. Hord
Westinghouse Electric Corp.
Org. Water Reactor Division
Address Pittsburgh, Pennsylvania

From Stan Bruske/Clair Ransom CBR
EG&G Idaho, Inc.
Org. NRC Licensing Support Section
Address Idaho Falls, Idaho

PROPOSAL TO PERFORM GENERIC EVALUATION - MC-35-84

Attached are five draft sections for Appendix C of our report dealing with the effects of control system failures on transients and accidents based on the H. B. Robinson Steam Electric Plant. These sections follow through our scenario development process and describe the computer analyses performed to deterministically evaluate the consequences of identified aggravating system failures. The justifications are provided for not performing computer analyses based on other aggravating system failures. The following report sections are for the identified Group 1 events:

C.2 Reactor Coolant System Pressure Increase Scenarios
C.3 Positive Reactivity Addition Scenarios
C.4 Increase in Reactor Coolant Inventory
C.5 Decrease in Reactor Coolant Flow
C.6 Decrease in Reactor Coolant Inventory Scenarios

If you have any questions regarding these materials or this task, please call Stan Bruske at 208-526-9345, (FTS 583-9345) or Clair Ransom at 208-526-4362 (FTS-583-4362).

jm

Attachment:
As Stated

w/o attachment:
cc: P. E. Litteneker - DOE
R. E. Lyon
C. F. Obenchain
E. W. Roberts
A. J. Szukiewicz - NRC (w/attachment)

EG&G Idaho **NOTEGRAM**

FORM EG&G-460 A
(Rev. 04-79)

Date September 5, 1984

To: Ray Calvo
Org.: Westinghouse Electric Corp. Water Reactor Division
Address: Pittsburgh, Pennsylvania

From: Stan Bruske/Clair Ransom SB CBR
Org.: EG&G Idaho, Inc. NRC Licensing Support Section
Address: Idaho Falls, Idaho

PROPOSAL TO PERFORM GENERIC EVALUATION - MC-35-84

Attached is the appendices volume of our report dealing with the effects of control system failures on transients and accidents at the H. B. Robinson Steam Electric Plant. These appendices contain the results of the FMEA, a detailed H. B. Robinson model description, and a discussion of the scenario development process and computer analyses (Appendix C includes and supercedes Sections C.2 through C.6 that were previously transmitted to you).

We have also enclosed a plot of the feedwater flow rates for Reactor System Overcool Sequence Number 1 per your request. The enclosed steam dump flow plot is the correct plot for Reactor Coolant System Overcool Sequence Number 1 and should replace Figure 2 on page 25 of the main report.

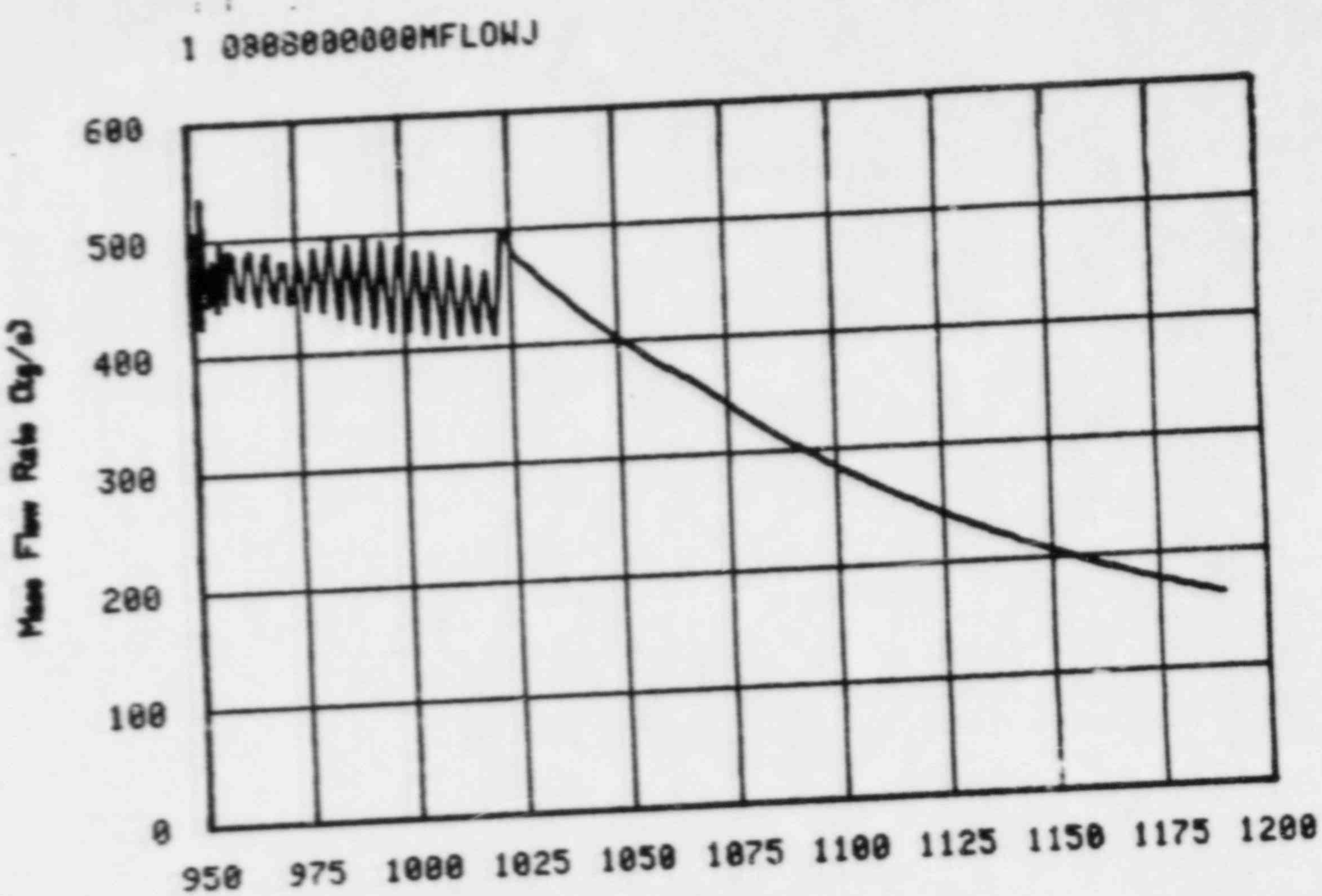
A check was made to verify that the correct steam dump and steamline PORV flow rates were provided in the report. This check showed that, based on the information that we received from CP&L, the indicated flow rates are accurate for the plant conditions that existed during the computer calculations.

If you have any questions regarding these materials or this task, please call Stan Bruske at 208-526-9345, (FTS 582-9345) or Clair Ransom at 208-526-4362 (FTS 583-4362).

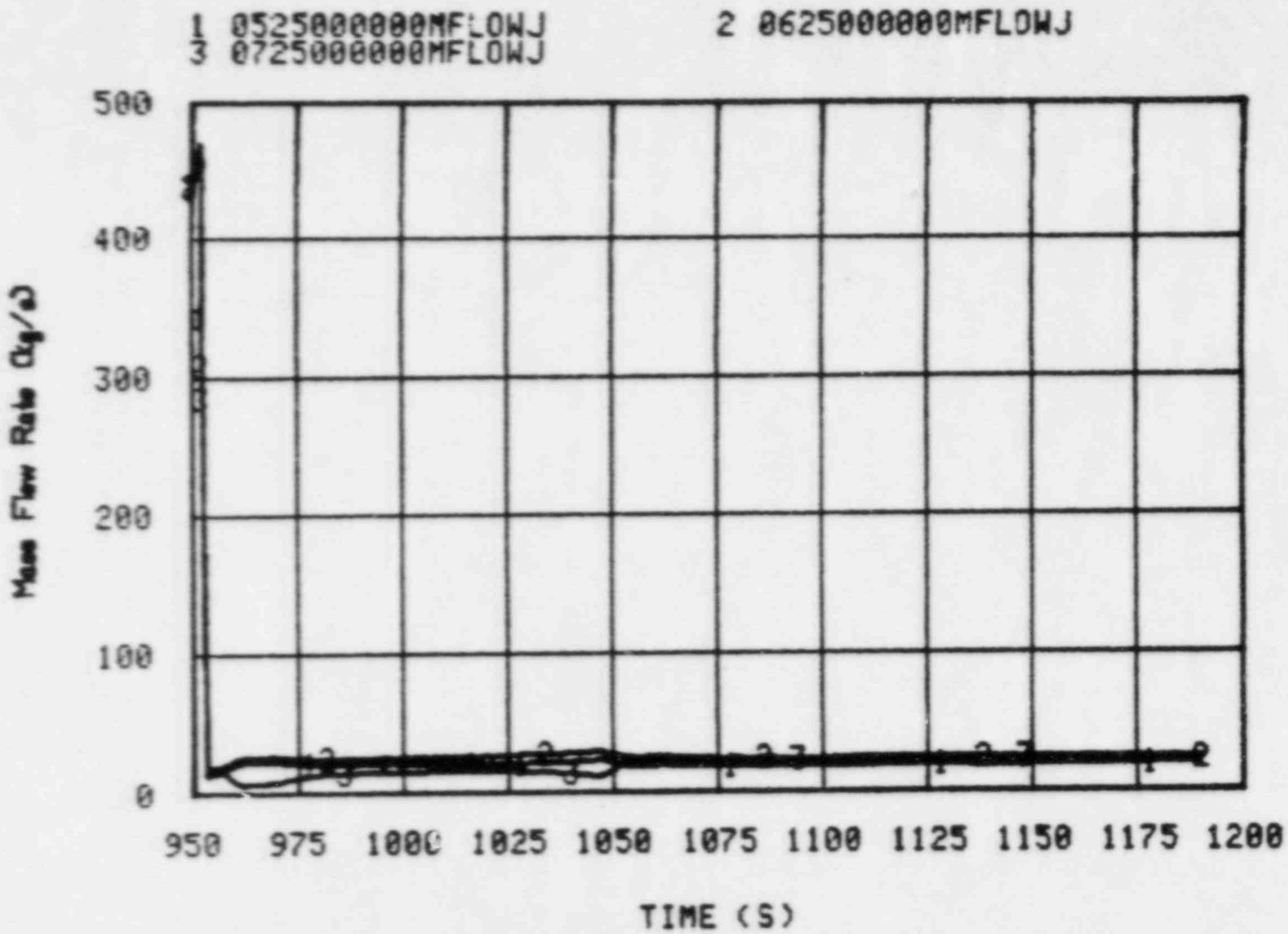
jm

Attachment:
As Stated

cc: w/o Attachment
P. E. Litteneker - DOE
R. E. Lyon
C. F. Obenchain
E. W. Roberts
A. J. Szukiewicz - NRC (w/Attachment)



HBR OVERCOOLING TRANS 1
FLOW OUT STEAM DUMPS



HBR OVERCOOLING TRANS 1
FEEDWATER FLOW RATES