Water Hammer Prevention, Mitigation, and Accommodation

Volume 6: Review of Plant Systems and Procedures

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REPORT SUMMARY

Water Hammer Prevention, Mitigation, and Accommodation

Volume 6: Review of Plant Systems and Procedures

Water hammer events continue to be responsible for costly equipment damage and plant outages. This report identifies plant system configurations and operating procedures that are susceptible to water hammer.

INTEREST CATEGORIES

Nuclear component reliability
Nuclear plant operations and maintenance
Light water reactor safety

KEYWORDS

Water hammer
Piping systems
Piping loads

BACKGROUND Although water hammer events in nuclear power plants do not constitute a significant safety risk, their occurrence can result in equipment damage, which can adversely affect plant operation. EPRI established this research project to help significantly reduce the impact of such events, if not eliminate them.

OBJECTIVE To identify which plant system configurations and operating procedures are susceptible to water hammer.

APPROACH The researchers collected plant-specific data from several nuclear power stations that had experienced significant water hammer events. The data included information on plant configurations and procedural practices.

RESULTS Areas susceptible to water hammer have been identified on a system-by-system basis. The report includes a description of the phenomena initiating water hammer and how existing procedures and designs affect the possibility of water hammer.

EPRI PERSPECTIVE Water hammer events still occasionally occur in nuclear power plants, sometimes causing damage to plant components and piping systems. These events can affect plant operation and availability through forced plant outages. The results of other tasks in this project are reported in the other volumes of this report. These include a compilation of reported events (volume 1); a determination of root causes of reported events (volume 2); a description of experimental data on water hammer (volume 3); a description and assessment of analytic models and computer codes applicable to water hammer assessment (volume 4); and guidelines for water hammer prevention, diagnosis, and assessment (volume 5).

PROJECT
RP2856-03
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Contractors: Stone & Webster Engineering Corporation;
Bechtel Group, Inc.

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Water Hammer Prevention, Mitigation, and Accommodation

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ABSTRACT

Even though water hammer events have been investigated for years, they continue to be a major cause of costly equipment damage in nuclear power plants. The Electric Power Research Institute (EPRI) has initiated a multi-year project to prevent water hammer events in nuclear power plants and to help utilities mitigate and accommodate their impact. The final product of this project will be a comprehensive water hammer handbook for plant engineers and operators.

The project is divided into nine integrated tasks. This report presents the results of Tasks 6 and 7 which are based on water hammer experiences at several plants.

Plant-specific data have been collected relative to some of the systems susceptible to water hammer in typical boiling water reactor (BWR) and pressurized water reactor (PWR) nuclear plants. These data are reviewed and evaluated to identify system configurations and operating procedures that are susceptible to water hammer, to provide guidelines to diagnose the root causes of the water hammer events, and to evaluate the corrective actions taken by the utilities to prevent recurrence of the events.

ACKNOWLEDGEMENTS

This phase of the project benefitted from the interest and cooperation of several utilities that hosted plant visits. The Electric Power Research Institute (EPRI), Stone & Webster Engineering Corporation (SWEC), and Bechtel Group, Inc. (BGI) wish to acknowledge the excellent cooperation afforded us by these unidentified utilities.

Project team members from Northeast Utilities (M. Kupinski, P. Godha), Yankee Atomic Electric Company (R.T. Fernandez), Bechtel Group, Inc. (H.H. Safwat, A.H. Arastu) and SWEC, including Project Engineer W. Yow, are acknowledged for their contribution to this report and its review.

CONTENTS

ILLUSTRATIONS

ILLUSTRATIONS (Continued)

ILLUSTRATIONS (Continued)

ILLUSTRATIONS (Continued)

TABLES

Section 1

INTRODUCTION

OVERALL PROGRAM

Electric Power Research Institute (EPRI) has initiated a multi-year project to prevent water hammer events in nuclear power plants and to help utilities mitigate and accommodate their impact. Stone & Webster Engineering Corporation (SWEC) has been selected as prime contractor with subcontractors including Bechtel, Northeast Utilities Services Company, and several world-renown consultants. The results of this project will be integrated into a comprehensive water hammer handbook for plant engineers and operators.

A summary of the defined tasks and expected deliverables follows:

Task 1 - Compile and Classify Plant Water Hammer Experience

Survey utilities for water hammer events and compile and classify these events into types of plants and root causes.

- Provide a report documenting the database of power plant water hammer experience

- Provide a summary of water hammer statistics

Task 2 - Perform Root Cause Analysis for Water Hammer

Analyze root cause of water hammer and identify reasons for events.

- Perform root cause analysis of reported water hammer events
- Summarize remedial actions taken by utility

Task 3 - Compile Experimental Data on Water Hammer

Search out and review industry and laboratory experimental data on water hammer.

- Collect and review experimental database

- Evaluate experimental database according to water hammer mechanisms
- Identify areas where supplemental test data are required

Task 4 - Review Analytical Models and Computer Codes

Select computer codes for water hammer analysis and review their application.

- Provide a description of analytical models including benchmark and assessment of each code
- Evaluate the effectiveness of each code

Task 5 - Develop Guidelines to Prevent, Diagnose, and Assess Water Hammer for Utility Engineers

Generate useful guidelines for diagnosing, preventing, and assessing water hammer events.

- Provide guideline to diagnose water hammer
- Provide guideline to prevent water hammer
- Provide guideline to assess impact of water hammer

Task 6 - Collect Plant Data and Perform in-Plant Verification

Collect plant information, establish procedural practices, and perform verifications.

- Identify system components and piping arrangements susceptible to water hammer
- Review design and procedural practices for fluid systems susceptible to water hammer

Task 7 - Review Plant Specific Operating Procedures and Designs

Review the considerations pertaining to water hammer in plant design and procedures.

- Describe strengths and weaknesses of fluid systems susceptible to water hammer

- Provide specific improvement or enhancement recommendations

Task 8 - Develop Training Modules

Prepare lessons learned and water hammer mitigation training information.

- Provide a training module on water hammer lessons learned, water hammer technology review, and on water hammer prevention, diagnosis, and assessment.

Task 9 - Technology Transfer as Negotiated with EPRI

Provide technology transfer services to utilities to enhance the project results as authorized by EPRI.

OBJECTIVES OF TASK 6

The objectives of Task 6 of this project are to:

- Collect data to establish plant specific fluid system configurations, identifying component features and functions for systems susceptible to water hammer.

- Establish industry practice guidelines with regard to fluid systems and components affecting or affected by water hammer during the implementation of testing, maintenance, and operating procedures.

- Perform in-plant verification for the guidelines developed in Task 5 to prevent, diagnose, and assess water hammer.

OBJECTIVES OF TASK 7

The objectives of Task 7 are as follows:

- Review plant specific fluid system operating procedures and designs for considerations given to water hammer.

- Describe water hammer susceptibility of the plant specific fluid system operating procedures and designs, including the in-plant monitoring systems and guidelines utilized in Task 6 testing, reviewed with regard to provisions to prevent water hammer events.

- Develop recommendations for improvements to plant specific fluid system operating procedures and designs to reduce the potential for water hammer.

APPROACH OF TASKS 6 AND 7

In order to accomplish the above-mentioned objectives, Tasks 6 and 7 were each further subdivided into several subtasks. The preliminary phase of Tasks 6 and 7 was performed at approximately the same time during several plant visits to participating utilities as reported in (1). The general approach that was used is described below.

Collect Plant Information

The first subtask of Task 6 is to collect plant specific data and documents (e.g., piping and instrumentation diagrams (P&IDs), system descriptions, as-built piping drawings, piping isometrics, component design specifications, vendor component data sheets, and operating tests and maintenance procedures) from participating utilities for those systems analyzed in this task, and also to support the design and procedural reviews and evaluations performed in Task 7. Plant specific data were collected from systems at several nuclear power stations which have experienced significant water hammer events.

Establish Procedural Practices

The second subtask of Task 6 is to evaluate industry procedural practices obtained from the participating utilities with regard to fluid system components affecting or affected by water hammer during the implementation of testing, maintenance, and operating procedures.

The final phase of Task 6 includes performing examples of in-plant verifications for the water hammer prevention, diagnostic, and assessment guidelines which were developed in Task 5.

Review of Plant Specific Operating Procedures and Designs

Plant specific documents collected and system plant configurations generated in Task 6 are utilized in performing the review required by Task 7.

With the results from the above analysis, a list of strengths and areas susceptible to water hammer for each system evaluated were developed. Included in the list is a description of the phenomena initiating water hammer and how existing procedures and designs prevent water hammer events, or are deficient in doing so.

The final phase of Task 7 includes preparing and documenting plant specific recommendations where improvements or enhancements can be made in the existing procedures and designs for each system evaluated. When considering design changes that have hardware implications, as part of the recommendation, options for cost effectiveness from the utility perspective are considered.

DELIVERABLES OF TASKS 6 AND 7

Task 6 yields the following items which are presented on a system-by-system basis later in this report:

- A list of active components for each system to be evaluated in Task 7.
- Procedural practice guidelines for fluid systems susceptible to water hammer during the implementation of testing, maintenance, and operating procedures.

Task 7 produces the following items which are presented with each system as noted above:

- A detailed description of the analysis performed for each system evaluated.
- List of strengths and areas susceptible to water hammer for the plant specific fluid system operating procedures and designs for each system evaluated.

REFERENCES

1. Van Duyne, D. A., Yow, W., and Safwat, H. H., "Water Hammer Prevention, Mitigation, and Accommodation, Tasks 6 and 7 - Collect and Review Plant Water Hammer Data, EPRI RP-2856-3, Preliminary Tasks 6 and 7 Report," October 1988.

Section 2

TYPES OF SEVERE WATER HAMMER

The majority of the water hammer events experienced in a nuclear power plant are caused by acceleration or deceleration of fluid flowing in a piping system, such as in the case of a pump startup or a valve closure. This type of water hammer mostly occurs in a single-phase flow environment. The pressure waves generated from these transients which propagate at sonic velocity can be easily determined by using the conventional water hammer techniques which have been verified by experimental and field measurements. The root causes associated with these events are generally well understood. Direct damage from these events is usually insignificant when the resulting loads are accommodated in the piping design.

There are certain other water hammer events, however, which involve two-phase flow mixtures that have resulted in severe water hammer effects. The most severe of these are events induced by rapid condensation of steam which cause local but violent impact of water slugs. These events are more complex to analyze, but they can have a profound impact on plant operation and usually cause significant damage to pipe supports and piping components. Obviously, these severe condensation events should be prevented if at all possible.

MECHANISMS FOR SEVERE WATER HAMMER

The necessary physical and mechanical conditions for potential water hammer events to occur in the nuclear power plant exist all the time. Although this potential has been minimized in most situations by ensuring that proper system design and operational procedures are instituted, water hammer events still occur.

Water hammer occurrences can be classified in two basic categories:

- Normal (anticipated)
- Severe (unanticipated)

A normal or anticipated water hammer event is defined here as one that is expected to occur during normal system operation and should not cause physical damage. A severe or unanticipated event is beyond the original design considerations and may result in physical damage. This report addresses severe water hammer in two-phase flow situations.

Typical normal water hammer transients are those caused by pump start, pump trip, control or isolation valve operation, check valve closure, safety and relief valve operations, main steam turbine trip, and the filling of normally empty systems. These anticipated water hammers usually occur in a single-phase flow environment. Their effects can be easily determined by using conventional water hammer analysis techniques which have been verified by experimental and field measurements. The root causes associated with these events are generally well understood.

There are several other water hammer events, however, which have resulted in severe water hammer effects. These events are more complex to analyze because they usually occur in a transient two-phase flow environment. They can have a profound impact on plant operation and often cause significant damage to pipe supports or piping components.

Seven specific mechanisms or transient scenarios have been identified which can lead to severe water hammer. These scenarios are the primary focus of this research project. The first four water hammer mechanisms are classified as condensation-induced events, although Mechanism 3, like Mechanism 7, can be dominated by the head generated by the pump rather than the resulting low pressure generated by the steam pocket collapse. Mechanism 5 is classified as a water slug induced event while Mechanism 6 relates to rapid valve operation and Mechanism 7 is classified as filling of a voided line.

Mechanism 1. Subcooled water with condensing steam in a vertical pipe (Water Cannon)

Mechanism 2. Steam and water counterflow in a horizontal pipe (Steam/ Water Counterflow)

Mechanism 3. Pressurized water entering a vertical steam-filled pipe (Steam Pocket Collapse)

Mechanism 4. Hot water entering a low pressure line (Low Pressure Discharge)

Mechanism 5. Steam-propelled water slug (Water Slug)

Mechanism 6. Rapid valve actuation (Valve Slam)

Mechanism 7. Filling of a voided line (Column Rejoining)

The damage in severe water hammer events is caused by either a pressure wave traveling at sonic velocity in water or a fast-moving water slug. Mechanism 5 is the only clear case of a water-slug-induced water hammer. Mechanism 6 is a single-phase flow transient which occurs under abnormal valve operation such as failure or sticking and produces a significant pressure wave. Mechanism 4 is a special case of an abrupt velocity change which creates a significant pressure wave that travels upstream. The remaining mechanisms, 1, 2, 3, and 7, each have a two-phase flow condition of steam or vapor and water in which the water impacts either a closed valve, pipe bend, or a stationary column of water, creating a severe pressure wave that travels through the water-filled regions of the system. In summary, all of these seven scenarios except Mechanism 5 create severe pressure wave transients.

Three additional categories of other classifications of the reported events are also listed.

Mechanism 8. Other or unknown

Mechanism C. Cavitation/Valve Instability

Mechanism N. Non-water hammer event

A brief explanation of each mechanism is provided below.

<u>Mechanism 1.</u> Subcooled water with condensing steam in a vertical pipe (Water Cannon)

This mechanism, often described as "water cannon," has occurred in several HPCI* and RCIC* systems of BWR power plants where steam lines discharge into the

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*See Table 2-3 for key to plant systems abbreviations used in this report.

suppression pool. The water cannon event begins as steam exhausts into a pool of subcooled water, as shown in Figure 2-1(a)-(d). If the flow of steam is stopped or reduced significantly (such as by fully or partially closing the exhaust valve), a pocket of steam gets trapped above the subcooled liquid surface. The rapid condensation of the trapped steam draws water quickly into the exhaust line. The water impacts onto the fully or partially closed valve, causing a substantial pressure pulse which travels through the water-filled pipe creating significant forces on the pipe segments.

<u>Mechanism 2.</u> Steam and water counterflow in a horizontal pipe (Steam/ Water Counterflow)

Figure 2-2 illustrates steam and water counterflow in a horizontal pipe. This has occurred often in the PWR feedwater lines to the spargers in the steam generators.

During steam and water counterflow in a horizontal pipe, a large interfacial area exists between the steam and subcooled water, as shown in Figure 2-2. Typically this occurs while injecting a small flow of subcooled water into a large horizontal pipe leading to a reservoir of high-pressure steam. Rapid condensation on the liquid surface induces a high-velocity steam flow counter to the direction of liquid water flow. Under the proper conditions this countercurrent flow will cause a transition to slug flow, and a steam pocket as shown in Figure 2-2(b) will be formed. Rapid condensation of the trapped steam results in a large differential pressure across the slug of water formed by the trapping wave. This slug is accelerated into the collapsing void as shown in (b) resulting in a moderate water hammer. Alternatively, as filling continues, the water bridges the elbow and forms an isolated steam pocket (c) in which the steam condenses dropping the pressure. This causes the slug to accelerate.

When the steam pocket finally vanishes (d), the slug is rapidly stopped and large pressure waves can be generated. These waves also propagate through the piping system and can result in severe damage.

Mechanism 3. Pressurized water entering a vertical steam-filled pipe (Steam Pocket Collapse)

This kind of water hammer has occurred in many BWR RHR systems, a few BWR RWCU systems, and PWR CCP and SI systems.

Pressurized water entering the bottom of a vertical pipe or one that is inclined upward more than 3° from horizontal can result in a steam pocket collapse transient. The filling rate for this mechanism is determined primarily by the inertia of the liquid and the pressure developed by the pump or other filling device, instead of pressure differential caused by the condensation of the steam pocket. A steam-filled pipe may exist at any plant elevation and is usually caused by the leaking of steam or hot water which flashes from a higher pressure region.

Figure 2-3 shows two cases: bottom filling and top filling. The effect of the steam condensation for both cases is secondary to that of the inertial effect as noted above. As water fills a steam-filled pipe from the bottom, Figure 2-3(a), the steam pocket collapses and the water impacts a closed, or nearly closed, valve causing a significant pressure pulse in the system as shown in Figure 2-3(b).

A water hammer will not occur with a slow rate of top filling as shown in Figure 2-3(c). However, if the top filling rate is faster than the bubble rise velocity, the slug flow pattern shown in Figure 2-3(d) will occur. A water hammer will occur when the slug flow fills the pipe and any bubbles rapidly collapse. A pressure wave will then propagate through the water-filled piping.

Mechanism 4. Hot water entering a low pressure line (Low Pressure Discharge)

Hot water entering a lower pressure line has caused significant water hammer transients in many power plants, especially in the heater drain dump systems that discharge to the condenser. Several events have also been reported in the PWR FW and SGB systems and a couple in the BWR MSR system.

Figure 2-4(a) shows the pressurized water at saturation temperature in a tank which is connected to a discharge pipe containing stagnant subcooled water adjacent to the closed valve inlet. When the valve opens, this subcooled water quickly passes the valve and a water hammer may occur due to the difference in flow velocities of the hot and colder water which is flowing through the valve as shown in Figure 2-4(b). The velocity of the saturated water for the driving pressure available is smaller than that for subcooled water due to the choking effect at the valve.

Additional transients may occur downstream. Flashing of saturated water downstream of the valve may lead to the creation and propulsion of a water slug. Impact of the slug at a restriction, Figure 2-4(c), will cause a water hammer, but is considered as a special case of Mechanism 5.

<u>Mechanism 5.</u> Steam-propelled water slug (Water Slug)

Steam-propelled water slugs may occur in piping systems which collect condensate upstream of a closed valve, Figure 2-5(a), or those that could form water slugs in normally empty steam discharge lines (c). Most events have been reported in the turbine-steam side of the BWR HPCI and PWR AFW systems. Several events have occurred in BWR IC and MS systems and PWR MS and RCS systems.

Figures 2-5(a) and (b) illustrate the case of a slug being propelled by steam. The water hammer transient begins when the valve is opened which allows the steam flow to accelerate the water slug. A relatively modest steam pressure across the slug (e.g., 25 psi) can produce significant slug velocity and large forces when this rapidly-moving slug passes an elbow or hits a restriction in the piping system. When condensate collects in a normally empty line, Figure 2-5(c), the initial slug might not completely fill the pipe cross-section. The flowing steam could "sweep up" the water into a slug similar to Figure 2-5(b), resulting in a significant water hammer.

Mechanism 6. Rapid valve actuation (Valve Slam)

Rapid valve actuation transients are defined as rapid closure of a stuck-open check valve as shown in Figure 2-6(a) or abnormal valve opening or closing events such as those due to actuator failure, Figure 2-6(b). Abrupt pressure pulses result from these sudden changes in flow velocity which are more severe than normal valve opening or closing transients. Local column separation and rejoining could occur on the low-pressure side of these rapidly closing valves. Several events have occurred in BWR FW and MS systems and the PWR MS system.

Mechanism 7. Filling of a voided line (Column Rejoining)

Figure 2-7 illustrates the three steps of a water column separation and rejoining transient. A change in piping elevation of over 30 feet can lead to a formation of a vacuum following a pump trip if check valves leak or a keep-full system is not operating to prevent this. The void will collapse upon pump restart causing a substantial pressure pulse in the water filled piping. Many piping systems are susceptible to this type of water hammer mechanism, but most have occurred in BWR RHR systems. Several events have occurred in BWR HPCI, LPCS, and SCW systems and a few in PWR FW and RHR systems.

SUMMARY OF REPORTED WATER HAMMER EVENTS

Plant water hammer experience of publicly-reported events has been studied and reported in EPRI RP-2856-3, Task 1 Report (1). Events were grouped by various attributes including the development of a matrix for each severe water hammer mechanism for BWR and PWR plant systems as shown on Tables 2-1 and 2-2.

Additional systems which have similar attributes should be considered for possible water hammer. These are marked on these tables and are discussed in appropriate sections of this report. Some of these additional systems are non-safety and would, therefore, not have had all water hammer events reported publicly.

Each event shown in this matrix was classified by plant type (BWR or PWR) and by system to facilitate reference by utility engineers.

Each event was analyzed in the Task 2 Root Cause Report (2) to determine the areas of each system which are prone to water hammer, the specific water hammer mechanism, and root cause. The remedial actions taken by the utility to preclude future occurrence of a similar water hammer were described. Appendices A and B of (2) presented the BWR and PWR utility water hammer databases and Appendix C therein listed the utility plant codes used. Areas prone to water hammer were identified in typical schematics of each system discussed.

SYSTEMS OF INTEREST FOR FLUID TRANSIENTS

Since the water hammer prevention guidelines are intended for use by the utility engineers, it is important that the guidelines cover in detail those piping systems that experience water hammers. Utility representatives were asked to check off the systems of interest for fluid transients on a form similar to Table 2-3. It was noted that water hammers may be severe enough to be a safety concern and require reporting, or they may be enough of a nuisance to cause concern. Some signs of water hammer include broken cables or damaged instrument lines, pipe motion accompanied with loud bangs or rumbling motion, inoperable snubbers, loosened or missing bolts, spalled concrete, pipe/elbow deformations, etc.

To date, there have been 18 responses for PWR plants and 8 for BWR plants. The results of this survey are tabulated on Table 2-3.

The PWR systems of interest agree very well with the systems which reported water hammers as shown on Table 2-2 with two significant exceptions - the feedwater heater drains and steam generator. The first is a non-safety system so transients usually do not get publicly reported. The SG water hammer problem has generally been resolved, but is not completely without transients, and is of less interest at the present time. The preliminary Task 6 and 7 Report(3) did include a discussion of a severe transient in the FWHD system, and utility engineers have expressed keen interest in the FWHD system.

The BWR systems of interest agree generally with the systems which reported water hammers as shown on Table 2-1. Most respondents indicated an interest in FWHD systems on BWR plants as they did on PWR plants. Also, the systems such as HPCI, LPCS, and RHR, where water hammer problems have been resolved by means such as keep-full systems and spargers, are currently of less interest.

CONDENSATION INDUCED WATER HAMMER

Mechanisms 1, 2, 3, and 4 may lead to severe condensation induced water hammers, with Mechanism 2 events being potentially the most severe. The water cannon events (Mechanism 1) may occur if the right geometry and system conditions exist. Pressurized water entering a vertical steam-filled pipe (Mechanism 3), although similar in some respects to the filling of voided line of Mechanism 7, can cause a severe transient event over a wider range of piping geometry conditions. Hot water entering a lower pressure line (Mechanism 4) is also a very common condition for many nuclear power plant piping systems, especially for those heater drain dump lines which lead to the condenser.

Condensation induced water hammers of the Mechanism 2 type can occur in a horizontal pipe with a steam and water stratified environment. If the water is highly subcooled, violent condensation may occur. This rapid condensation process will generate a significant steam flow above the water surface. The shearing forces at the interface between the steam and the subcooled water can create enough turbulence to generate a water slug which in turn will entrap an isolated steam pocket. Continued rapid condensation of the entrapped steam will accelerate the water slug into the void, causing a damaging water hammer. Two conditions must co-exist in the system to initiate the Mechanism 2 condensation induced water hammer, namely:

- A steam and subcooled water stratified flow exists in a significant length of a horizontal or near horizontal pipe
- Substantial turbulence exists at the steam-water interface

Depending on the void fraction and subcooling in the two-phase flow environment, the magnitude of the pressure wave generated by steam condensation and bubble collapse can be devastating. These events should be prevented from occurring by all practical means.

In summary, the significant condensation induced water hammer mechanisms are:

Mechanism 1	Subcooled Water with condensing steam in a vertical pipe
Mechanism 2	Steam and water counterflow in a horizontal pipe
Mechanism 3	Pressurized water entering a vertical steam-filled pipe
Mechanism 4	Hot water entering a lower pressure line

Examples of water hammer events caused by condensation of steam are described in the following sections of this report:

Section 3	Feedwater: Venting and Draining Operation (Mechanism 2) Feedwater: Steam Generator Water Hammer (Mechanism 2)
Section 4	Heater Drain: Third Point Heater Transient Dump Line Isolation Valve Operation (Mechanism 4)
	Heater Drain: First Point Heater Transient Dump Line Emergency Control Valve Operation (Mechanism 4)
	Heater Drain: First Point Heater Transient Dump Line Isolation Valve Operation (Mechanism 3)
Section 5	Steam Generator Blowdown: Steam Generator Blowdown Initiation After System Isolation (Mechanism 4)
Section 8	Residual Heat Removal: Transient in Letdown Line Upon Flow Initiation (Mechanism 3)
Section 9	Core Spray: Pump Startup with Steam in the Line (Mechanism 3)

WATER SLUG INDUCED WATER HAMMER

Water slug induced water hammers often occur in steam lines where condensate has accumulated due to improper drainage while the system is in standby. When steam flow is initiated in the water-plugged line, the water slug accelerates by the differential pressure across it, until the slug impacts upon another column of water or an obstruction such as an elbow, a check valve, or a restricting orifice. The impact force generated by such an event can be very destructive as it depends upon the momentum of the water slug which can be very large.

The water slug induced water hammer mechanism is:

Mechanism 5	Steam-Propelled Water Slug

Examples of water hammer events caused by water slugs are described in the following section of this report:

Section 6	Auxiliary Feedwater: Turbine-Driven Auxiliary Feedwater Pump Start
Section 11	Isolation Condenser: Water Slugs in the Steam Supply Line
Section 12	Main Steam: Steam Bypass Valve Lift Following Turbine Trip With a Water Slug in the Line

WATER HAMMER DUE TO RAPID VALVE OPERATION

Transient pressures can be generated in a pipe by rapid valve opening or closing. Under normal operating conditions, most valves are operated at a relatively slow rate and any pressure waves created do not exceed the system design basis. Therefore, the water hammers induced by valve operation being investigated in this study include only the abnormal valve operating conditions, such as the rapid closure of a stuck-opened check valve or the rapid operation of a valve with a failed actuator. These types of abnormal valve operation generate significant pressure waves and forces, and can cause damage to piping components or pipe supports.

In summary, the water hammer mechanism due to rapid valve actuation includes rapid closure of a stuck-opened check valve, and rapid closure of a worm-gear driven large butterfly valve due to actuator failure. The water hammer mechanism is:

Mechanism 6 Rapid Valve Actuation

Examples of water hammer events caused by rapid valve operation are described in the following sections of this report:

Section 7	Low Pressure Safety Injection: Pump Startup During Testing
Section 8	Residual Heat Removal: Closure of RHR Pump Recirculation Flow Control Valve
Section 12	Main Steam: Stop Valve Closure on a Turbine Trip

WATER HAMMER DUE TO FILLING OF A VOIDED LINE

Filling of the voided space in a pipe with excessively higher elevation above the water source can result in moderately severe water hammer upon impact of the water columns after system startup. The water hammer mechanism is identified as:

Mechanism 7 Filling of a voided line

Examples of water hammer events caused by filling of a voided line or by water column separation and rejoining are described in the following sections of this report:

Section 3	Feedwater: Feedwater Minimum Flow Recirculation Line
Section 8	Residual Heat Removal: Inadvertent Closure of RHR Pump Suction Valve
Section 9	Core Spray: Pump Startup with a Voided Line
Section 10	Low Pressure Coolant Injection: Pump Startup with a Voided Line (two events)

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2. Van Duyne, D. A., Yow, W., and Sabin, J. W., "Water Hammer Prevention, Mitigation, and Accommodation, Task 2 - Root Cause Analysis for Plant Water Hammer Experience," EPRI RP-2856-3, Task 2 Report, December 1989.

3. Van Duyne, D. A., Yow, W., and Safwat, H. H., "Water Hammer Prevention, Mitigation, and Accommodation, Tasks 6 and 7 - Collect and Review Plant Water Hammer Data," EPRI RP-2856-3, Preliminary Tasks 6 and 7 Report, October 1988 (being updated herewith).

Table 2-1

WATER HAMMER CLASSIFIED MECHANISM BY BWR PLANT SYSTEM

PLANT SYSTEM	AS	CW	CON	FPS	FW	HPCI	IC	LPCS	MS	FWHD (MSR)	RCIC	RCS	RHR	RWCU	SCW	TOTAL
MECHANISM IDENTIFIED																
1 – Water Cannon	0	0	0	0	0	7	0	0	0	0	7	0	0	0	0	14
2 – Steam/Water Counterflow	0	0	1	0	0	1	0	0	1	0	0	0	0	0	0	3
3 – Steam Pocket Collapse	0	0	0	0	0	0	0	1	0	0	1	0	17	2	0	21
4 – Low Pressure Discharge	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	2
5 – Water Slug	1	0	1	0	0	15	3	0	4	0	0	0	0	0	0	24
6 – Valve Slam	0	1	0	0	5	1	1	0	2	0	0	1	0	0	0	11
7 – Column Rejoining	0	0	0	1	0	6	0	8	0	0	2	0	12	0	6	35
Severe Water Hammer Events	1	1	2	1	5	30	4	9	7	2	10	1	29	2	6	110
8 – Other or Unknown	0	0	2	0	0	4	0	1	0	0	0	0	5	0	1	13
C – Cavitation/Valve Instability	0	0	0	0	4	0	0	0	2	0	0	0	2	0	7	15
N – Non–Water Hammer Event	0	1	0	0	4	2	1	1	1	6	0	0	0	1	5	22
BWR Total Events Reported	1	2	4	1	13	36	5	11	10	8	10	1	36	3	19	160

$\cancel{0}$ Additional Systems To Be Considered

Table 2-2

WATER HAMMER CLASSIFIED MECHANISM BY PWR PLANT SYSTEM

PLANT SYSTEM / MECHANISM IDENTIFIED	AFW	CCP	CWS	CON	CT	CVCS	FPS	FW	FWHD	MS	RCS	RHR	ASW / SCW	SG	SGB	SI	TOTAL
1 – Water Cannon	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 – Steam/Water Counterflow	1	0	0	0	0	3	0	6	0	0	0	2	0	30	0	0	42
3 – Steam Pocket Collapse	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	3	5
4 – Low Pressure Discharge	0	0	0	0	0	0	0	4	0	0	0	0	0	0	6	0	10
5 – Water Slug	7	0	0	0	0	0	0	1	0	3	3	0	0	0	0	0	14
6 – Valve Slam	0	0	0	0	0	0	0	1	0	3	0	1	1	0	0	0	6
7 – Column Rejoining	0	0	0	0	1	0	0	2	0	0	0	3	2	0	0	1	9
Severe Water Hammer Events	8	2	0	0	1	3	0	14	0	6	3	6	3	30	6	4	86
8 – Other or Unknown	2	0	0	3	0	2	0	4	0	2	1	1	1	0	0	2	18
C – Cavitation/Valve Instability	1	0	0	0	0	0	0	9	0	0	0	0	0	0	0	0	10
N – Non–Water Hammer Event	0	0	1	1	1	2	1	0	1	0	2	0	0	0	0	0	9
PWR Total Events Reported	11	2	1	4	2	7	1	27	1	8	6	7	3	30	6	6	123

0 Additional Systems To Be Considered

Table 2-3

SYSTEMS OF INTEREST FOR FLUID TRANSIENTS

PWR PLANT SYSTEMS 18 RESPONSES	Check Systems of Interest	BWR PLANT SYSTEMS 8 RESPONSES	Check Systems of Interest
AFW – Auxiliary Feed Water	12	AS – Auxiliary Steam	0
ASW – Auxiliary Saltwater	1	CW – Condenser Circulating Water	0
CCP – Component Cooling Water	1	CON – Condensate System	4
CCW – Condenser Circulating Water	2	FPS – Fire Protection	1
CON – Condensate System	7	FW – Feedwater System	5
CT – Containment Spray	1	HPCI – High Pressure Coolant Injection	3
CVCS – Chemical & Volume Control	3	IC – Isolation Condenser System	2
FPS – Fire Protection	2	LPCS – Low Pressure Coolant Injection	1
FW – Feedwater System	14	MS – Main Steam	2
FWHD – Feedwater Heater Drains	12	MSR – Moisture Separator Reheater	1
MS – Main Steam	7	RCIC – Reactor Core Isolation Cooling	2
RCS – Reactor Coolant System	2	RCS – Reactor Coolant System	0
RHR – Residual Heat Removal	8	RHR – Residual Heat Removal	5
SCW – Service Cooling Water	5	RWCU – Reactor Water Cleanup	2
SG – Steam Generator	1	SCW – Service Cooling Water	4
SGB – Steam Generator Blowdown	6	FWHD – Feedwater Heater Drains	6
SI – Safety Injection	7		
		– Core Spray	1
		– Condensate Storage & Transfer	1

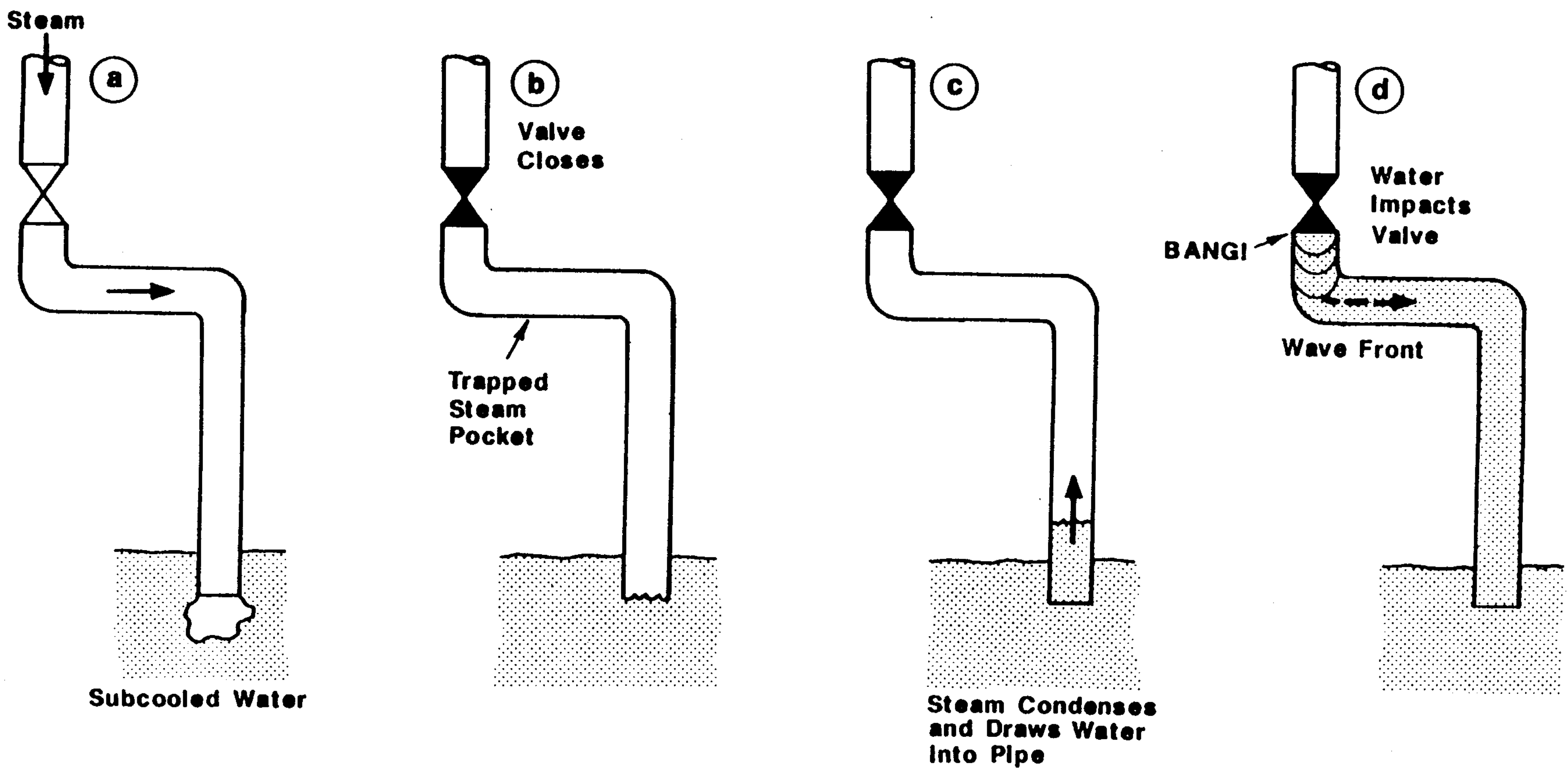


Figure 2-1. Mechanism 1 - Subcooled Water with Condensing Steam in a Vertical Pipe (Water Cannon)

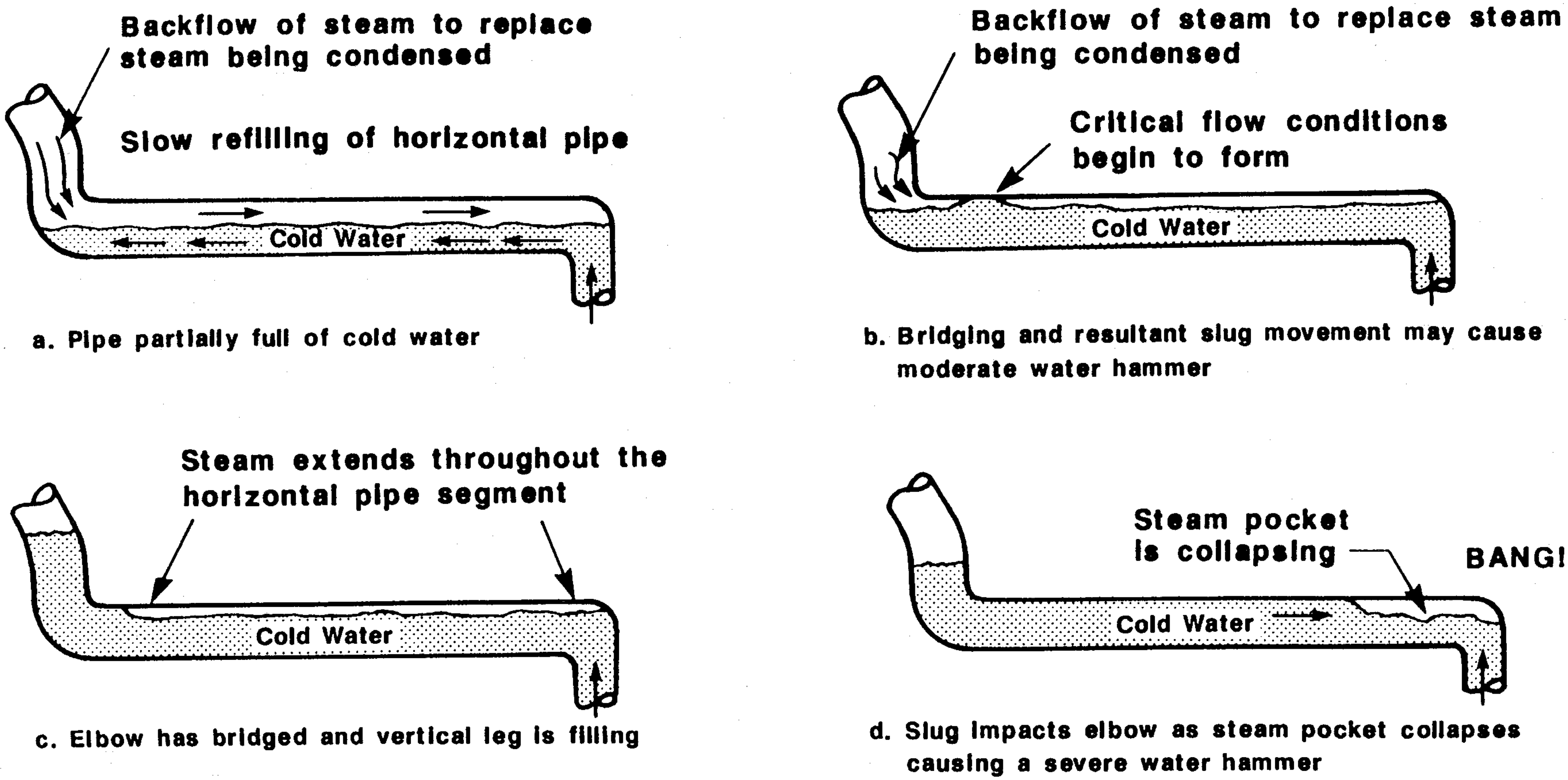


Figure 2-2. Mechanism 2 - Steam and Water Counterflow in a Horizontal Pipe (Steam/Water Counterflow)

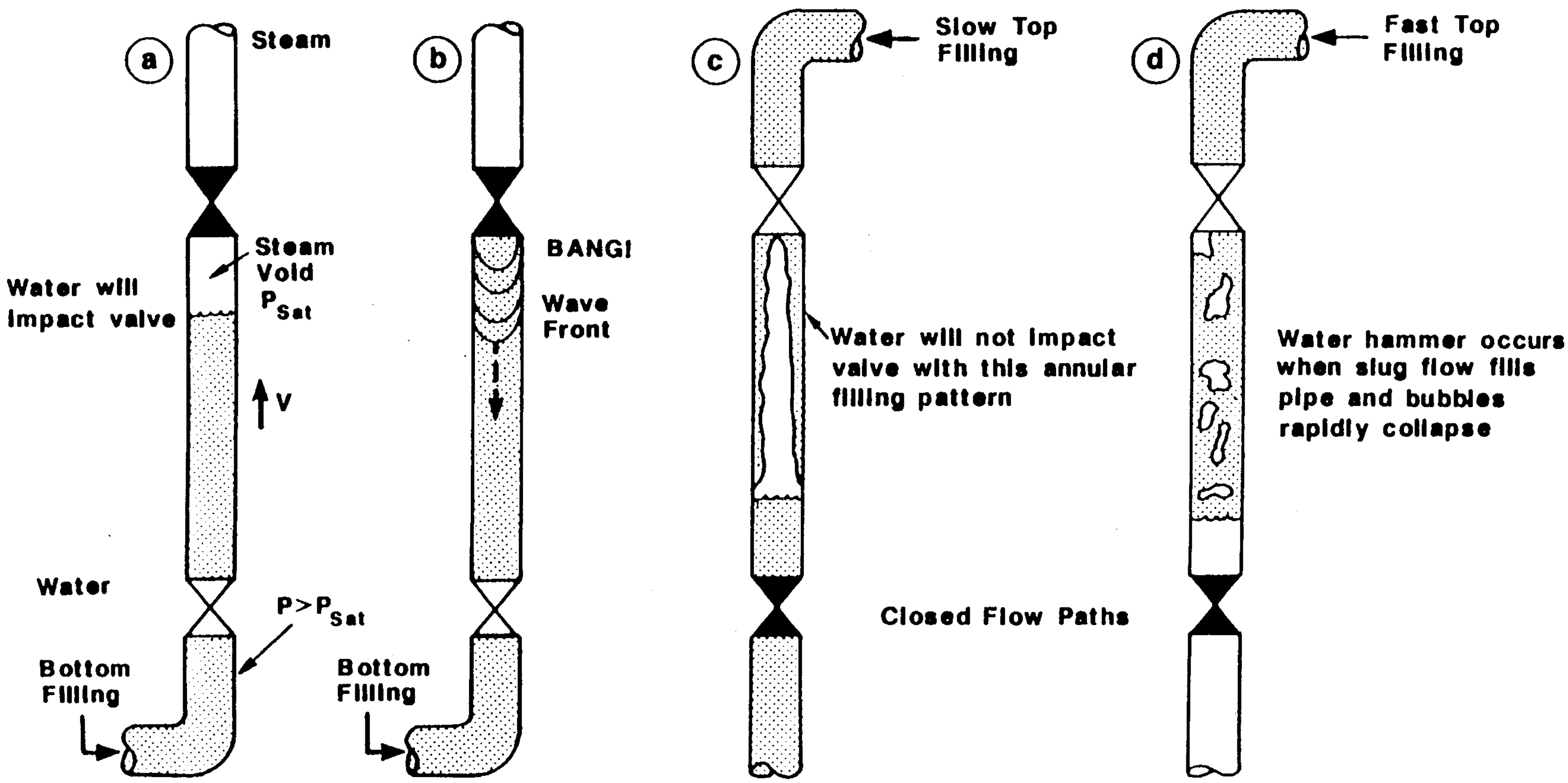
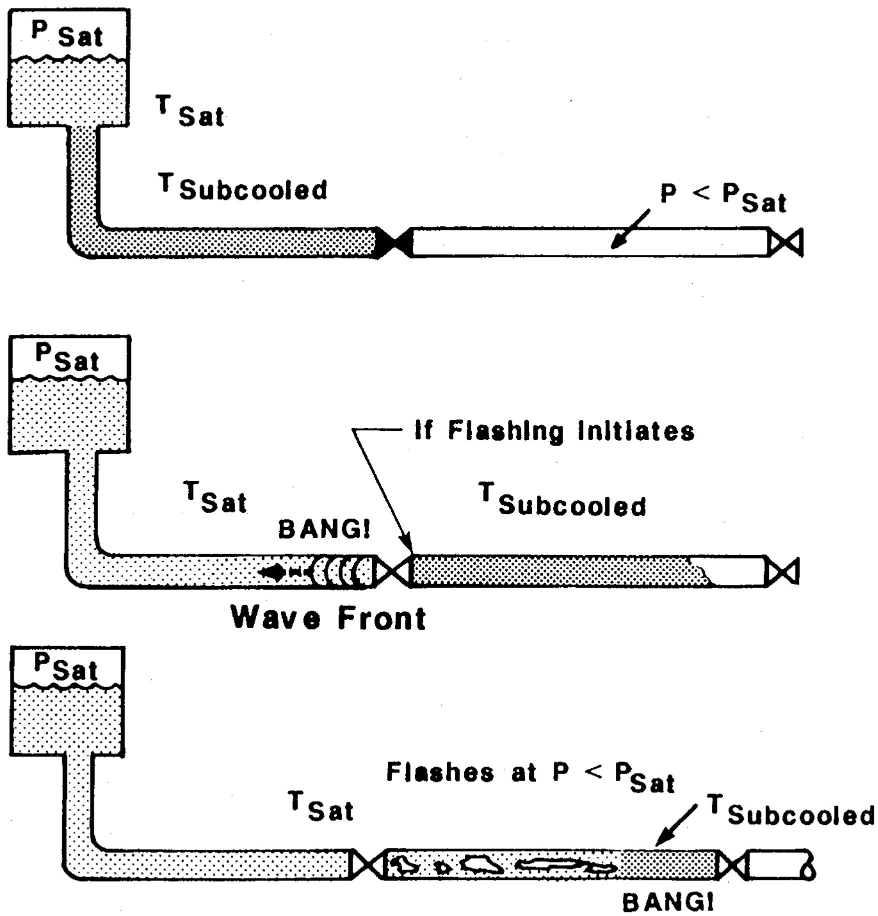


Figure 2-3. Mechanism 3 - Pressurized Water Entering a Vertical Steam-Filled Pipe (Steam Pocket Collapse)

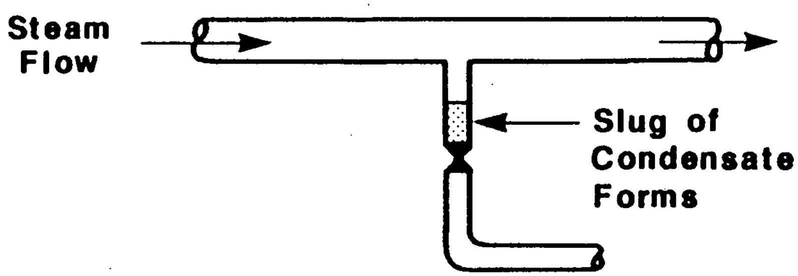


a. Initial conditions when valve opens

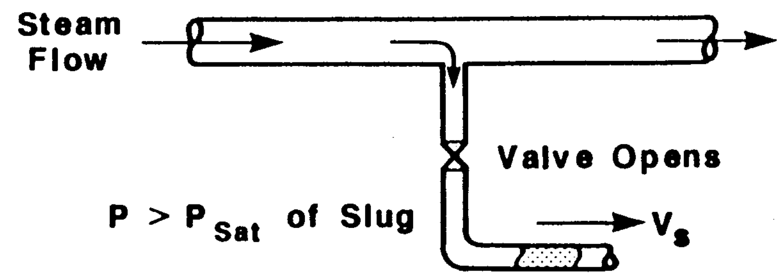
b. Possible water hammer when hot water reaches first valve or any significant restriction in the flow path if flashing occurs.

c. Hot water may flash downstream of the first valve which will propel cool water causing slug flow water hammer upon impact with downstream valve (See Mechanism 5)

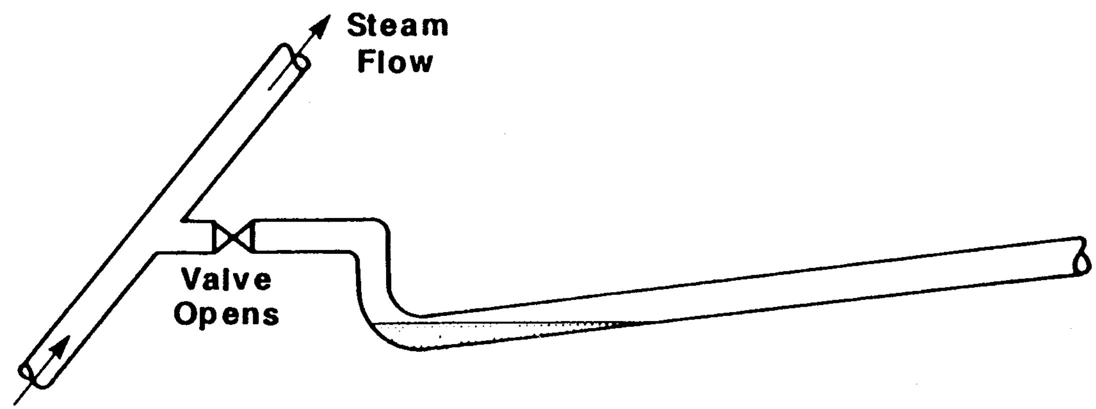
Figure 2-4. Mechanism 4 - Hot Water Entering a Lower Pressure Line (Low Pressure Discharge)



a. Slug forms in closed drain line



b. Rapidly moving slug loads pipe due to impact on elbows or restrictions



c. Water pipe forms slug as steam sweeps past, causing slug loads noted in b

Figure 2-5. Mechanism 5 - Steam-Propelled Water Slug (Water Slug)

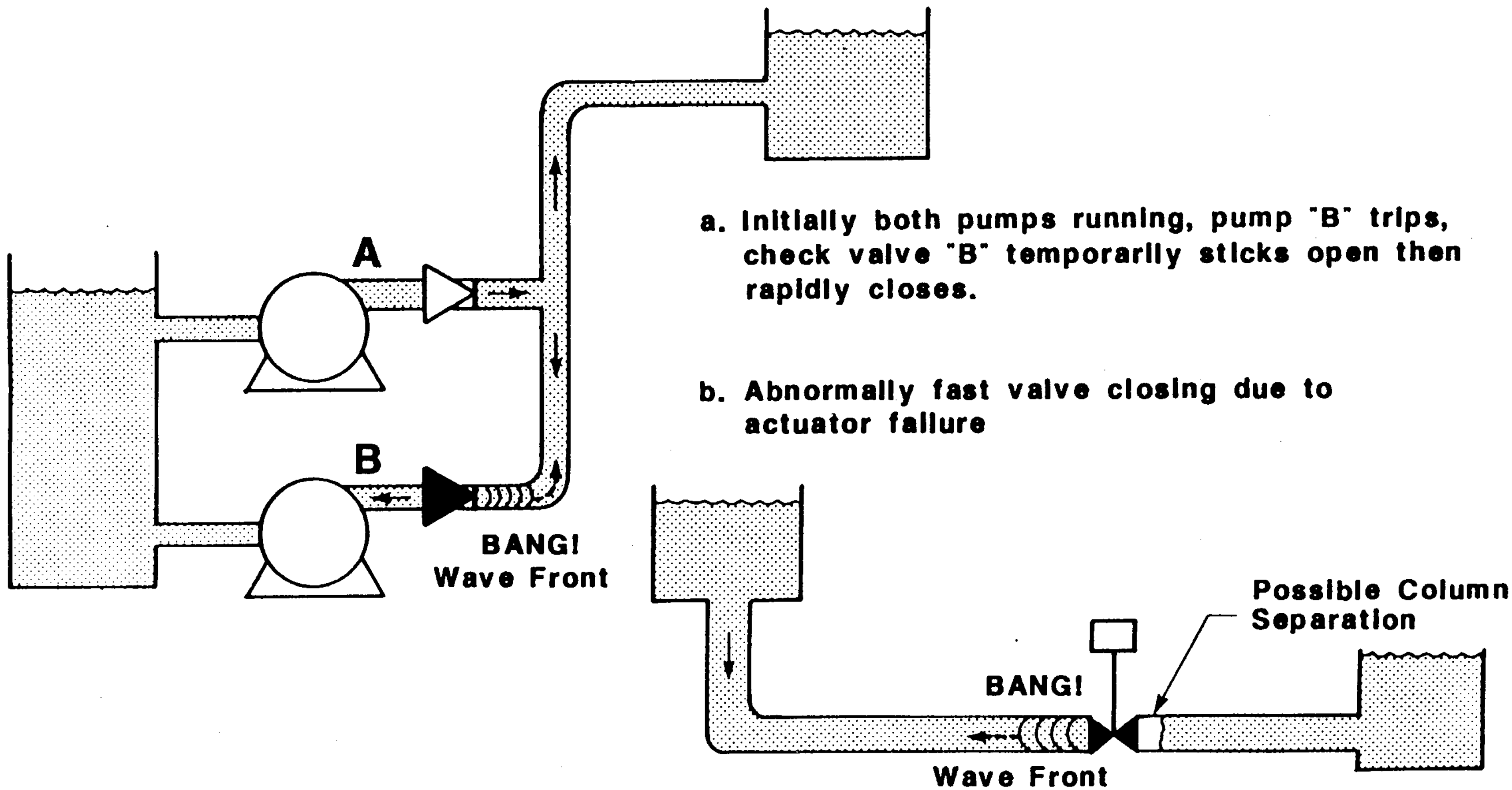


Figure 2-6. Mechanism 6 - Rapid Valve Actuation (Valve Slam)

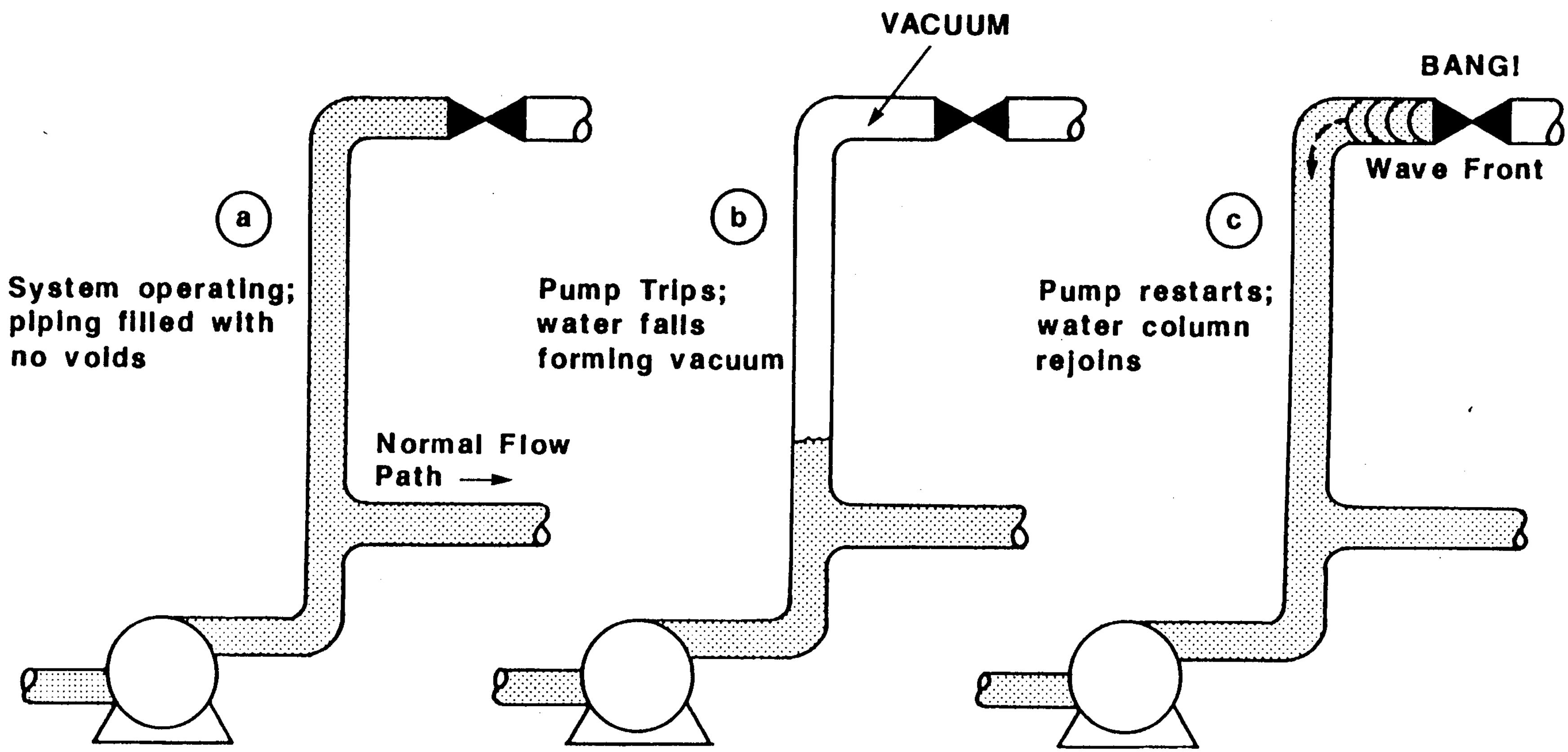


Figure 2-7. Mechanism 7 - Filling of a Voided Line (Column Rejoining)

Section 3

CONDENSATE, MAIN AND AUXILIARY FEEDWATER SYSTEMS IN PWR

SYSTEM FUNCTION

The functions of the feedwater system are to:

- Transport high pressure water from the condensate system to the steam generators.
- Heat feedwater to meet the Nuclear Steam Supply System (NSSS) vendor's temperature requirements at the steam generator inlet.
- Automatically control the water level, in conjunction with the NSSS vendor's steam generator water level control system, in the steam generators during steady state and transient conditions.
- Regenerative feedwater heating increases power plant cycle efficiency.

The main emphasis of this section of the report is on the main feedwater system. However, the condensate system between the condenser shell and the feedwater pumps, and the auxiliary feedwater system between the condensate storage tank and the injection points to the main feedwater system are also reviewed herein for water hammer.

This combined condensate and main feedwater systems perform the function of a continuous heat sink required for the reactor primary coolant. It is required under all anticipated steady state and transient normal operating conditions and is not a safety related system. Additionally, it provides turbine exhaust head spray, seal water to heater drain pumps, steam generator feed pumps, and the main condenser rubber boot seal expansion joint.

Auxiliary Feedwater System (AFW) is designed to supply feedwater to the steam generators during plant startup, shutdown and emergency conditions. During emergency conditions the AFW is switched on automatically to supply water to the steam generators to cool the RCS and thereby prevent release of reactor coolant through the pressurizer safety valves.

It should be noted that the design of condensate and feedwater system varies among different plants. The events described in this section have occurred in two different plants.

SYSTEM CONFIGURATION, MODE OF OPERATION AND COMPONENT DATA (PLANT B)

Configuration

Condensate and Feedwater. The feedwater system receives partially heated feedwater from the condensate system. It completes heating the feedwater to within the temperature range required by the NSSS vendor and raises its pressure to the value required to feed the steam generators. Figures 3-1 and 3-2 show schematic for a feedwater system for one plant and condensate and feedwater systems for another plant under normal full power operation.

Feedwater pumps take suction from the condensate system and discharge to a common header. One or multiple stages of regenerative feedwater heating is provided by two feedwater heater strings connected in parallel between the pump discharge header and a heating system designed to provide sufficient mixing to ensure that uniform temperature feedwater is supplied to each steam generator.

The feedwater is directed to the steam generator feed lines.. Each feed line has a feedwater flow control valve and a feedwater isolation valve. The flow control valves are positioned by a signal from the steam generator water level control system. The flow control valves, in conjunction with the feedwater pumps, maintain the desired steam generator water level. The feedwater isolation valves ensure isolation of feedwater flow to the steam generator on a feedwater isolation signal.

Two bypass lines are provided around each feedwater flow control valve. These bypasses allow for the control of feedwater flow to maintain the steam generator water level during low power operation or hot shutdown.

Each feedwater pump is provided with a minimum flow recirculation line which ensures proper low flow pump operation and prevents the pumps from overheating.

The recirculation flow is directed back to the condenser.

Figure 3-2 is a schematic diagram of the condensate and feedwater systems for plant B. Figure 3-4 is an elevation diagram showing the layout of the system. Two motor-driven condensate pumps take suction from the main condenser shell. The pumps increase condensate pressure to approximately 477 psig, delivering about 21,000 gpm at 100 percent load. The condensate pumps are vertical, multistage, motor-driven centrifugal pumps. The condensate then passes through five stages of preheating prior to the suction of the steam generator feedwater pumps (SGFP). The SGFP are horizontal single stage, centrifugal type and turbine driven. The SGFP raises the feedwater pressure to approximately 1,200 psig prior to passing it through the sixth and seventh stages of (high pressure) preheating. All the feedwater heaters in the plant are shell and tube type heat exchangers. The condensate flows through the U tubes and heating steam enters on the shell side. Following the final preheating, the water passes through the feedwater regulating valve, which is controlled by the steam generator water level control system. The steam generator water level control system maintains a programmed level in the steam generators as a function of turbine load. The feedwater then passes through the feedwater isolation valve and into the feedwater ring in the steam generator.

<u>Auxiliary Feedwater System</u>. Figure 3-3 shows a schematic of the auxiliary feedwater system. The auxiliary feedwater system provides a means of feeding the steam generators in the event of a loss of non-emergency A.C. buses or loss of feedwater accident. Typically, a total of 440 gpm of AFW flow into two of the four steam generators is required within 60 seconds of the start signal to prevent excessive temperature rise of the RCS.

Referring to Figures 3-3 and 3-4 for plant B configuration, the turbine-driven (P-102A) and diesel-driven (P-102B) AFW pumps are identical six stage centrifugal pumps, each rated at 960 gpm, including an 80 gpm recirculation flow with a total dynamic head of 3,400 feet. The turbine-drive AFW pump operates with steam from the Main Steam System.

The AFW pumps are normally supplied via a single suction line from the condensate storage tank. This line contains a dissolved oxygen analyzer and also receives the discharge of the shutdown morpholine pump. This line then branches into two separate lines each supplying one of the two pumps. The lines are provided with a manually operated isolation valve and a check valve.

Each AFW pump discharge line is provided with a check valve and an isolation valve. A continuous flow recirculation line taps in between the discharge of each pump and the check valve. The recirculation lines join into a single line that returns to the condensate storage tank. The discharge line then branches into four lines, one to each steam generator. Each of the four lines is provided with a 3 inch motor-operated control valve (CV 3004), a downstream check valve, and manually-operated isolation valves (see Figure 3-4) upstream and downstream of the control valve.

The single AFW line then joins through a check valve to the main feedwater line between the feedwater line isolation check valve and containment.

The electric driven AFW pump is also designed to produce 1000 gpm of flow at 3400 ft of head. It is a centrifugal pump driven by a 1250 HP AC motor. It is a non-safety grade pump and is used to supply feedwater only during shutdown and startup periods. It was added later on to the plant in order to minimize wear and tear on the safety grade pumps of the AFW system and has no automatic start features.

Active Components

- Flow Control Valves
- Low Power Flow Control Valves
- Isolation Valves
- Feedwater Isolation Check Valves
- Bypass Isolation Valves
- Bypass Check Valves
- High Pressure Feedwater Heater Isolation Valves
- High Pressure Feedwater Heater Bypass Valves

Vent Valve
Drain Valve
Feedwater Pumps
Feedwater Pump Discharge Check Valves
Condensate Pumps and Discharge Check Valves
Auxiliary Feedwater Pumps, Isolation Valves, Check Valves, and Control Valves
Minimum Recirculation Flow Control Valves

Condensate and Auxiliary Feedwater Systems Operating Modes

Normal Operation

The Condensate and Feedwater System is designed to provide a continuous supply of feedwater, at the required pressure and temperature, to the steam generators under all anticipated steady state and transient conditions of normal plant operation. At 100 percent plant load the total condensate flow rate is approximately 21,000 gpm. During normal plant operation two trains of condensate pumps, two trains of SGFP and two trains of feedwater heaters are in operation (50 percent flow per train). However, the Condensate and Feedwater System can supply the feedwater for plant operation up to 70 percent of the full rated load with only one of the two trains of pumps and feedwater heaters in service.

During the normal plant operation, the feedwater flow rate to each of the individual steam generators is controlled by air operated feed regulating valves (CV520 as shown in Figure 3-4) which themselves are controlled by the steam generator water level control system.

Emergency Operation

For the isolation of the steam generators from the Condensate and Feedwater System in the event of a main steam line break, two separate control channels are provided in addition to the Steam Generator Isolation signal. A signal from either channel will close the (air operated) feedwater control valves (such as

FCV520 for line B which is shown in Figure 3-4) and the downstream isolation valve (MO2971 B in Figure 3-4).

The steam generator feedwater pumps are tripped automatically upon receiving the appropriate signals.

As mentioned earlier, if one of the two trains is out of service due to either a loss of condensate pump, feedwater pump or any feedwater heater, the plant can be operated at any load up to 70 percent of full rated load. However, during the transient following a trip of one of the two steam generator feedwater pumps when the plant is operating at full load, the other steam generator feedwater pump can supply sufficient water (with two condensate pumps and two heater trains in operation) to prevent reactor trip. With a failure of one of the two condensate pumps when the plant is operating at full load, a reactor trip would occur.

In the event of loss of normal feedwater, the auxiliary feedwater pumps will start automatically and supply water for safe shutdown of the plant. In the event of failure of both condensate pumps, the steam generator feedwater pumps will automatically trip and this in turn will start the auxiliary feedwater pumps. If there is a break in Seismic Category II piping of the condensate and feedwater piping, the steam generator level will fall and on Low-Low level the auxiliary feedwater pumps will be automatically started.

Both the steam and diesel driven AFW pumps can be started manually or automatically upon appropriate signal.

The turbine driven pump is capable of supplying feedwater to the steam generators should a loss of all A-C power occur.

In the event of low level in the Condensate Storage Tank, the auxiliary feedwater pumps will trip and the operator can open the required valves to switch the supply to the service water system.

Normal Plant Shutdown

During normal shutdown, the feed flow reduces to less than 3 percent of full flow in about 1 hour, and the main feedwater pump continues to supply feedwater.

After this period the electric motor-driven auxiliary feedwater pump is used under manual control to supply condensate from the Condensate Storage Tank to the steam generators. The auxiliary feed flow to each steam generator is controlled by a motor-operated control valve, and the steam generated is dumped to the main condenser. The steam generator pressure reduced to 450 psig in approximately two hours.

The AFWS continues to operate and supply feedwater to the steam generators until the reactor coolant reaches 350°F, at which time the Residual Heat Removal (RHR) System is utilized for further cooldown of the reactor coolant. The condensate pumps can also be used during this period to supply condensate to the steam generators until reactor coolant reaches 350°F and the RHR System takes over.

Startup

The Condensate and Feedwater System is initially filled by starting the condensate transfer pumps. These are two parallel pumps each having a rated flow of 150 gpm and rated head of 234 ft (about 100 psi). They take in suction from the condensate storage tank and are connected by 4-in. lines to the condensate pump discharge lines at points upstream of the flow elements FE2972A,B (see Figure 3-4).

The condensate pump or the electric motor-driven auxiliary feedwater pump is then used to supply feedwater to the steam generators until sufficient steam pressure is generated to allow startup of the steam generator feedwater pumps.

Interfaces with Other Systems

a) Reactor Coolant System (RCS): The primary function of the Condensate and Feedwater System is to remove heat from the RCS and generate secondary steam for the plant. The AFS is also used to cool the RCS.

b) Main Steam System: The secondary steam for the plant is created in the steam generators due to the boiling of water delivered by the Condensate and Feedwater System and the AFWS.

   The feedwater pumps and one AFW pump are turbine driven. The steam required for these turbines is taken from the main steam system. The steam that is finally condensed in the condenser shell forms the main source of water for the Condensate and Feedwater System.

c) Exhaust Hood Spray: A secondary function of the condensate system is to supply exhaust hood spray to the low pressure turbines.

d) Condensate and Feedwater Chemical Injection System (CFWCIS): The CFWCIS is designed to provide adequate conditioning chemicals to the feedwater for prevention of scaling and corrosion.

e) Service Water System (SWS): The normal source of water for the AFW pumps is the condensate storage tanks. In case of failure from this source, water can be supplied to the safety related pumps from Seismic Category I SWS through appropriate manual valve lineup.

<u>Control Logic</u>

<u>Automatic System Operation</u>

The feedwater flow to each steam generator is regulated automatically by a three-element feedwater flow control system. The three element controllers regulate the control valves, by continuously comparing the feedwater flow to the steam generator level with a programmed water level in the steam generator and the steam flow signal.

The feedwater control valve and the downstream isolation valve are closed to isolate the steam generators. The Condensate and Feedwater System is isolated from the generators by any of the following signals from the Engineered Safety Features Actuation System (ESFAS):

- Two of three High-High steam generator level signals from any of the steam generators.
- Any of the conditions which causes a SIS (Safety Injection Signal).
- Low $T_{average}$ in coincidence with the reactor trip.

The feedwater pumps are regulated by a control system which governs the speed of the turbine drivers. The steam generator feedwater pumps are tripped automatically on any of the following trip signals:

- Steam generator High-High level
- Feedwater isolation signal from the Engineered Safety Features Actuation System (ESFAS)
- Any conditions which cause a safety injection signal (SIS)
- High pump discharge or low pump suction or low lube oil pressure
- Pump turbine driver overspeed, exhaust low vacuum, exhaust high temperature or thrust bearing wear

The AFWS is provided with the necessary control system to operate automatically. The AFWS is started automatically when the Condensate and Feedwater System is not available. Other conditions that will automatically start the system are given below:

- Tripping of both steam generator feedwater pumps.
- Low-Low water level signals from two out of three level transmitters of any steam generator.

- Any of the conditions which cause a Safety Injection Signal.

- Loss of normal onsite as well as preferred A-C electric power sources.

Manual System Operation

Manually operated valves are provided on the suction of all pumps, in each feedwater heater train at the inlet to the first-stage feedwater heater, the outlet of the fifth-stage feedwater heater, the inlet to the sixth-stage feedwater heater, and the outlet of the seventh-stage feedwater heater for isolation of the feedwater heater train when required.

The AFWS is provided with the necessary local or remote controls for manual operation of the system.

Instrumentation and Alarms

Necessary instrumentation, such as pressure indicators, flow indicators and temperature indicators, as required for monitoring the Condensate and Feedwater System, is provided in the control room.

A flow element with a transmitter and flow switch are installed on the discharge of each of the two condensate pumps. The flow switches provide the automatic signal to open the minimum recirculation valves for the condensate pumps. The flow transmitters provide the condensate flow input to the cooling tower blowdown controller. Level controllers are located on the condenser hot well for automatic control of system water makeup and reject.

A flow element with a flow switch is installed on the suction of each of the steam generator feedwater pumps to provide the automatic signal to open the minimum recirculation valves for the steam generator feedwater pumps. A pressure transmitter is located in the common feedwater header to provide the feedwater system pressure to the steam generator feedwater pump turbine speed control system. A flow element with two flow transmitters is located on the inlet to each of the four steam generators to provide signals for the three-element feedwater control system and the steam generator feedwater pump speed control system.

Pressure transmitters are provided in the discharge line of the auxiliary feedwater pumps and in the main steam lines from the steam generators. The pressure signals are transmitted the auxiliary feedwater pump speed control system for the safety-related pumps and to a flow control valve, CV-2967, for the electric motor-driven pump to maintain a preset differential between the pump discharge and the main steam line.

A transmitter is provided on the auxiliary feedwater line to indicate the flow to each steam generator. A conductivity element with a local indicator and a high conductivity alarm in the control room is provided for the safety- related pump minimum flow recirculation lines to detect leakage of service water into the AFWS during normal plant operation.

Pressure transmitters, each with an indicator and low pressure alarm in the control room, are provided for the safety-related pump suction lines to indicate a failure of water supply from the condensate storage tank (CST). A level transmitter is also provided on the Condensate Storage Tank for each of the safety-related pumps to provide automatic shutoff of the pump due to a low Condensate Storage Tank level. All the necessary instrumentation required for monitoring the operation of the pumps and drivers, are provided on local panels.

Filling, Venting, and Draining

The Condensate and Feedwater System has an adequate number of vents and drains for filling and draining the system. The filling of the system is monitored by opening the high points vents at various elevations. The vent locations are indicated in Figure 3-4 by the symbols V and VI inside a circle.

As the systems gets filled the various vents are closed. When water comes out of the vents in the 30-in. flow distribution headers and the vents at the outlet of heaters 105A and B, these vents are closed and the system pressure is maintained at 50 psig (as indicated by the pressure gauge at the outlet of the

SGFW pumps) by running at least one condensate transfer pump.

Component Data

Component data for major valves in plant B in the system are tabulated in Table 3-1. Data on pumps P2, P1, and P3 are given in Tables 3-2, 3-3, and 3-4, respectively. Characteristic curves for the steam generator feedwater pump, condensate pump, and auxiliary feedwater pump are given in Figures 3-5, 3-6, and 3-7, respectively.

WATER HAMMER EXPERIENCE

In the 1970s, a significant number of water hammer events were reported in LWR power plants (1), (2). This is so, because many power plants were built and began commercial operation in this time period.

Each event was analyzed in the Task 2 Root Cause Report (3) to determine the areas of each system which are prone to water hammer, the specific water hammer mechanism, and root cause. The remedial actions taken by the utility to preclude future occurrence of a similar water hammer were described. Appendices A and B of (3) presented the BWR and PWR utility water hammer databases and Appendix C therein listed the utility plant codes used. Areas prone to water hammer were identified in typical schematics of each system discussed.

Steam generator water hammer (SGWH), defined as the water hammer occurring due to the rapid condensation of steam in the secondary side of a PWR steam generator at the feedwater line connection (Mechanism 2), have been limited to the steam generators supplied by Westinghouse and Combustion Engineering (CE) and does not occur in the Babcock and Wilcox steam generators. In the Westinghouse and CE design, during the normal operation, the feedring that supplies water to the secondary side of the steam generators is fully submerged under water. Typical feedrings and the feedwater pipe attachments supplied by the three vendors of steam generators are shown schematically in Figure 3-8.

The mechanism causing the steam generator water hammer is now fairly well understood and the sequence of events leading to it are sketched in Figure 3-9.

The incidence of SGWH has been greatly reduced by plugging the bottom holes of the feedring and attaching J tubes on the top of the ring through which feedwater is discharged (see Figure 3-10).

Three events that have occurred in plants A and B that were reviewed during this project are discussed below in detail.

WATER HAMMER EVENT 1: VENTING AND DRAINING OPERATIONS

Event Description

Three events that have occurred in plants A and B that were reviewed during this project are discussed below in detail. While draining the feedwater header upstream of the flow control valves at the feedwater system of plant A, a minor water hammer occurred which resulted in noise and pipe movements up to 2 in. This particular draining operation involved opening a drain valve and subsequently opening and closing a vent valve intermittently. The draining operation commenced approximately 2 hours after the plant was shut down. When this draining operation commenced, the water being drained was reported to be relatively cool (estimated to be about 100°F by the draining operator), whereas the fluid exiting the vent valve was a two phase mixture of steam and water at a much higher temperature. The sequence of events and known relevant facts leading to the water hammer are provided below (see Figures 3-11 and 3-12):

- The plant was shut down and placed in a hot shutdown status. Makeup water to the steam generators was being supplied by the auxiliary feedwater system at approximately 1000 psig and 80°F. The feedwater pumps were not operating; however, the condensate pumps were in recirculation back to the condenser and therefore pressurized the feedwater system to approximately 700 psig. Because of the higher auxiliary feedwater pressure, flow due to any valve leakage would be directed back to the condensate/feedwater system (see Figure 3-11).

- Two hours after the plant was placed in hot shutdown the drain valve on the feedwater supply header upstream of the flow control valves was opened to commence draining the system piping. During the next 10 minutes, the vent valve located at the supply header high point was intermittently opened and closed. The drain rate was estimated to be approximately 20 to 25 gpm during this period and the drain temperature was about 100°F based on the fact that the operator was able to hold the flexible drain hose in his hand. The temperature of the fluid exiting the vent valve when it was opened was estimated to be about 230°F because it was a pressurized steam/water mixture.

- Three minutes after the vent valve was last cycled opened and closed, several water hammers were observed by plant personnel working in the area. The water hammers produced a loud banging noise and resulted in pipe movements up to 2 in.

- The vent valve was immediately opened and air was drawn into the pipe. No further water hammers were observed by plant personnel.

No damage to the feedwater piping and supports was identified by plant personnel as a result of the water hammer.

Mechanisms Responsible for the Event

Due to the piping configuration, initial system parameters, the sequence of events, and the supporting evidence provided by plant personnel, the mechanism responsible for this water hammer event is a condensation-induced water hammer caused by steam and water interaction in a horizontal pipe.

Analysis of Root Causes

System Temperature Gradient. Immediately after the plant shut down, followed by securing the feedwater pumps, the feedwater supply header pressure and temperature was about 700 psig and 500°F. Since the heat loss through the piping insulation is relatively small, and in order to support the temperature gradient observed by plant personnel two hours after the plant was shut down, the system must have experienced leakage from the pressurized auxiliary feedwater system through one or more of the flow paths as identified below (refer to Figure 3-11):

- The main feedwater control valve and its associated discharge check valves, and feedwater isolation valves.

- The low power feedwater flow control valves, and its associated isolation valves, and discharge check valves.

- The 2-in. manual bypass line which contains a block valve and check valve.

The back leakage from these flow paths merge downstream of the feedwater header and could possibly flow through the feedwater header and the first point heater isolation valves or its bypass valve back to the condensate system or the condenser. The leakage flow rate could have been as little as 3 gpm to accomplish the same system temperature variation identified by plant personnel. This rate of leakage may not be apparent to the reactor operator since it is not affecting steam generator levels or plant cooldown, and it could easily go unnoticed for two hours. In addition, the leakage rate is slow enough so as not to disturb the hotter fluid at the top of the pipe as the cold auxiliary feedwater flow cascades to the header low point.

Therefore, based on the scenario of backleaking for almost 2 hours after plant shutdown and prior to the initiation of the draining operation, the water in the horizontal pipe header with the vent valve in Section C of Figure 3-13 was thermally stratified with cold water at the bottom and hot water at the top. Section A with the drain valve collected the leaking colder water at about 100°F. Section B piping is also estimated to have collected much of this colder water. This is based on the volume displaced by the cold water backleaking through the closed valves.

Water Hammer Scenario. When the draining started, the flow coming out of the drain valve was the colder water (about 100°F) which had gravitated to the bottom of the pipe in Section A. When the vent valve was intermittently opened and closed, the hot water (about 230°F) which remained at the high point of the line exited through the vent valve and it quickly flashed into the steam-water mixture observed by the maintenance operators. As the venting and draining process continued to reduce the volume of water in the system, and consequently reduce the pressure of the two phase flow mixture, more hot water in the pipe flashed into steam. This process continued with intermittent venting for the first 10 minutes.

After draining for approximately 13 minutes at a rate slightly higher than 30 gpm (close to the original estimate made by plant personnel), the hot water at the top portion of the pipe, Section C shown in Figure 3-13, was replaced with steam and the subcooled water remained at Sections A and B of the pipe. The pressure was maintained at the saturation pressure of the hot water which is estimated at about 20.8 psia (for 230°F). This pressure was decreasing slowly as the draining and venting continued and the void became larger, but the pressure was still larger than atmospheric pressure.

As the draining process continued, the water level in the pipe gradually receded to slightly below the top elevation of the horizontal pipe at Section B, which allowed the hot steam to start penetrating this 10-ft long section of the colder 18-in. diameter horizontal pipe. The draining operation could also develop a void space downstream of the high pressure feedwater heater (Figure 3-1), thus creating void spaces at both ends of a U-shaped liquid column between the heater and the feedwater header. The intermittent operation of the vent valve had generated significant pressure surges within the steam and water mixture, which could induce the low frequency oscillation of surface waves on any horizontal section of subcooled water. Even though the pressure surges would reduce after the vent valve had been shut for a couple of minutes, the steam flowing into Section B due to the condensation by direct contact of steam with subcooled water and the cool pipe would continue to set up a wavy surface on the water. The turbulence of this wavy surface would be enhanced by the hydraulic disturbances created by the continued draining through the drain valve and the backleaking flow from the feedwater control block valves.

The wavy surface effect of the water entrapped a pocket of hot steam which had penetrated into the horizontal pipe. As the isolated steam pocket condensed by its interaction with the surrounding subcooled water and pipe, the pressure of the steam pocket rapidly decreased to the saturation pressure of the subcooled water, thus developed a differential pressure across the slug of water between the isolated steam pocket and the larger body of steam near the vent valve. The differential pressure then accelerated the slug which impacted the upstream elbow or another slug of water coming from the opposite direction. This slug impact created the water hammer observed by personnel in the area.

The disturbance created by the slug impact coupled with a large exposed horizontal surface of cool water further condensed a larger portion of the steam in the line and quickly depressurized the pipe to the saturation pressure of the cool water, which was below the atmospheric pressure. As a result, when the vent valve was opened, air was sucked into the system.

Water Hammer Root Causes. Based on the evidence and the scenario described above, the root cause of this event is procedural as described below:

- The back leakage of cold auxiliary feedwater flow through the trains of closed flow control valves, check valves, and isolation valves, into the hot region, resulted in significant thermal stratification due to the piping configuration and the draining of a hot water piping system prior to allowing it to cool down to less than 140°F.

This scenario could have occurred at Section A of Figure 3-13 had it not happened in Section B.

Corrective Measures

There are two corrective measures which the utility adopted for this event. First, the event could have been minimized by using the vent valve to continuously vent the system. In doing so, a very large portion of the stored energy within the system could be released, thus reducing the differential pressure (driving force) across the water slug, and hence minimizing the resultant loads. To implement this recommendation, however, a hard pipe vent line should be installed to the vent valve for proper venting without causing undue personnel safety hazard, component damage, or creating undesirable environmental effects during the draining and venting operational procedure. Secondly, and the preferred method, the water hammer would have been prevented if the system had been allowed to cooldown prior to draining the system for maintenance. The event has not reoccurred since the utility implemented these corrective actions.

WATER HAMMER EVENT 2: STEAM GENERATOR WATER HAMMER

Event Description

During a refueling outage at plant B, a walkdown of the feedwater system uncovered a damage due to water hammer to a seismic restraint SRB on the loop B feedwater line. The geometry of loop B feedwater line between the isolation check valve and the steam generator is shown in more detail schematically in Figure 3-14. During a previous year outage, visual inspection inside the containment showed that the seismic restraint SRB (shown in Figure 3-14) was intact. The restraint SRB is located near the containment. This is a strut rigidly connected to the 14-in. diameter feedwater line B and is designed to prevent pipe movement (thermal and seismic) in the east-west directions. However, during this refueling outage, inspections revealed that the restraint SRB on the B feedwater loop had failed and it was found that the restraint knee brace sleeve anchors had pulled out of concrete. The pull-out was more in line with a classical concrete anchor failure (i.e., fully developed conical concrete anchors were observed). A more detailed visual inspection revealed that the clamp had not "walked" on the pipe; clamp bolts were tight, pipe insulation was not disturbed, and no scratches or other marks were found on the pipe. Welds on the knee brace structure were sound. The strut itself, rated for a 10 kip dynamic load, was in excellent condition. No such damage or other abnormalities were observed on the restraint of feedwater line A. The water hammer event was not observed when it was occurring. It should be noted that only lines A and B have rigid seismic restraints SRA and SRB, respectively. Feedwater lines C and D have spring hangers.

The load required to impart the observed support failure was estimated to be statically about 40 kips.

Mechanism Responsible for the Event

Based on the discussions given in the next section, the mechanism causing the event is a condensation-induced water hammer caused by steam and water interaction in a horizontal pipe.

Analysis of Root Causes

In an attempt to establish the possible transient that produced the reported damage, "normal transient" hydrodynamic analyses were performed to evaluate the water hammer forces due to various valve closure cases. The closing time used for the isolation valve was 7 s; the closing time used for the flow regulating valve was 3 s and the check valve was modeled with the disc dynamics taken into account. The maximum force on the segments of the feedwater piping, inside the containment, was found to be about 20 kips. Hence, the water hammer due to valve closure was ruled out for the failure of feedwater restraint SRB.

A second possible cause of water hammer which had been investigated was check valve slamming. The check valves that could have contributed to the failure of the restraint were inspected carefully and found no evidence of water hammer impact. Thus, check valve slamming was also eliminated as a root cause.

A third possible cause of water hammer investigated was due to condensation induced water hammer. An analysis was performed to evaluate the loads on SRB due to a water hammer caused by rapid steam condensation. If T0 is the steam saturation temperature 557°F at the steam generator pressure of 1100 psia and T1 is the temperature of cold-water adjacent to the steam void, this analysis shows that the collapse of a steam bubble of size 20 cu in. in the 14-in. diameter feedwater pipe (upstream of the thermal sleeve), with a temperature differential (T0 - T1) of about 115°F, will generate a pressure wave that can load the restraint SRB to 40 kips. Based on the Tihange (9) results the ramp time of this wave was conservatively estimated as 1 ms. Figure 3-15 shows a schematic of an idealized void entrapped by moving slug from the steam generator side. Since the selection of the temperature differential of 115°F is arbitrary, it would be appropriate to indicate the sensitivity of the load on SRB in a range of values of T0 - T1. This is shown in Table 3-5. The initial volume of the void in Table 3-1 was assumed to be 20 cu in. Table 3-6 shows the effect of assuming a smaller initial void volume as 5 cu in. There is about 135 ft of piping between the auxiliary feedwater pump and the connection with the 14-in. feedwater line (near the feedwater isolation check valve, see Figure 3-4). Also the length of the 14-in. feedwater piping between the auxiliary feedwater connection and the steam generator nozzle is about 145 ft. It is difficult to establish whether the steam collapses before the arrival of cold auxiliary feedwater to the void. If the trapped steam bubble collapses before the arrival of the cold auxiliary feedwater then the temperature differential is much larger. From the plant data, it is known that the steam generator water level re-establishes to the normal level after its initial decrease following plant trip in about 4 s. Cold water from the AFW piping would not reach the trapped steam void before at least 25 s.

A calculation was performed to determine the static load at the restraint that would cause the observed damage and was found to be 40 kips. The calculation also showed that the hydrodynamic load on the 14-in. feedwater piping should be about 80 kips to translate into a load of about 40 kips at the SRB restraint. It was also determined from a dynamic loading analysis that a 615 psia transient (pulse), with a ramp time of 1 ms, in the feedwater line would produce a 40 kip load at the seismic restraint SRB.

Eight years prior to this event, a similar failure occurred in the restraint SRA on the loop A feedwater line. The restraint SRA is a mirror image of the restraint SRB on the loop B feedwater line. Just as for this SRB failure, the SRA knee brace sleeve anchors had pulled out of the concrete in the earlier incident. Due to the close similarity in the appearance of the two failures there is a high probability that the root cause is of the same nature. During the intervening years the auxiliary feedwater control valve (CV3004 shown in Figure 3-4) was throttled (350 gpm) to avoid the AFW pump low suction trip. During this period no incidents of steam generator water hammer have occurred. However, just prior to each water hammer event the AFW control valve was wide open allowing larger AFW flow (400 gpm) in horizontal feedwater line (near the steam generator nozzle) to collapse the trapped steam pocket giving rise to water hammer.

Corrective Measures

The occurrence of steam generator water hammers has diminished significantly by implementation of the J tubes modification. There have been two steam generator incidents that failed the seismic restraints in the feedwater lines of steam generators A and B. After the later incident, testing of the containment check valve showed that there was no leakage through it. However, inspection of the "B" steam generator nozzle showed that the annular gap between the sleeve of the feedring and the steam generator nozzle had increased from an initial size of 0.025 in. to larger size as big as about 0.25 in. in some spots twelve years later. After the feedring is uncovered this annular gap provides a path for the feedwater to drain out (see Figure 3-15). The empty space will be occupied by the steam resulting in a potential for steam generator water hammer to occur. This potential will be enhanced if the water chemistry is such that it causes an increase in the gap size of the feedring sleeve. Additionally, the problem of check valve failure/leakage is always there which may lead to a severe incident. However, by following proper maintenance, inspection and testing procedures it can be ensured that the feed regulating valve, motor operated isolation valve and the containment isolation check valve are closing completely and there is no leakage from the containment isolation check valve.

The gap size between the feedring sleeve and the steam generated nozzle is normally 0.025 in. which should not be allowed to exceed a certain tolerance level. This can be done by the proper chemistry control of feedwater. Absolute upper and lower limits of the auxiliary feedwater flow rates should be specified. The AFW flow rate should be always in this range. More experimental and theoretical studies may be needed in order to define these flow rates. The steam generator water level drops because there is no flow during an interval between the cut off of the feedwater flow and the arrival of the auxiliary feedwater flow in the feedring. Possibilities should be investigated to prevent this delay. For example by delaying the tripping of feedwater pumps until the auxiliary feedwater flow becomes available.

WATER HAMMER EVENT 3: FEEDWATER MINIMUM FLOW RECIRCULATION LINE

Event Description

An 8-in. recirculation line (see Figure 3-4) connects the high pressure discharge end of each of the feedwater pumps to the condenser. On several occasions, when the feedwater recirculation line was being used, a constant popping sound was audible. The sparger in the recirculation line at the condenser connection was found to be broken. This information was obtained during discussions with the plant personnel.

Mechanism Responsible for the Event

From a review of the piping components and system parameters it appears that the water hammer occurred due to column separation.

Analysis of Root Causes

Referring to Figure 3-4 the flow rate in the feedwater recirculation line is controlled by the valves (CV2976A,B). These valves are controlled by SGFP suction flow indicator switch. They open when the flow rate is less than 4000 gpm and close when the flow rate is 9000 gpm or more. The valve will also open automatically upon the tripping of its respective SGFP. The valve closure or opening time is about 25 s. The valves can either remain fully open or fully closed. At 4000 gpm flow rate, the liquid velocity in the pipe is approximately 26 ft/s. There is an orifice provided in each of the feed pump recirculation lines, which is attached to the condenser and produces a pressure drop of about 455 psi (at 4000 gpm). The pressure drop across the recirculation control valve is about 675 psi and with an additional 20 psi frictional loss in the piping the total pressure drop in the recirculation line is thus 1150 psi. A few years ago, spargers were added to the recirculation line which provides additional pressure drop.

When the plant is in the startup mode the recirculation line control valves CV2976A,B are open and when the flow rate of water in the feed pumps has reached about 9000 gpm these valves begin to close. At 8000 gpm the liquid velocity in the pipe is about 52 ft/s. When the control valve closes at such high flow rates, water column separation is likely to occur in the piping downstream of the valve (CV2976). The cavity grows to a maximum size and then collapses which causes the "popping" noise. The high pressure wave is reflected as a low pressure wave (from the condenser) which will start another bubble that will eventually collapse. The cycle of events gives rise to the constant popping noise which is a characteristic column rejoining.

Corrective Measures

- By increasing the size of the feedwater recirculation line (from 8 in. to 10 or 12 in.) the flow velocity in the piping will be reduced. This will reduce the potential for water hammer resulting from column separation occurring in the piping downstream of the control valve.
- Install a flow element in the recirculation line to monitor the exact flow rate during various plant modes.

SYSTEM EVALUATION

Normal Transients

The normal transients that occur in the Condensate and Feedwater System and the AFWS are valve closure/opening and pump trip/startup. The most severe case of valve operation appears to be concerning the control valves CV2976A,B in the feedwater minimum recirculation line. These recirculation valves are controlled by SGFP suction flow indicator switch. They open when flow rate is less than 4000 gpm and close when the flow rate is 9000 gpm or more. The valve will also open automatically upon the tripping of its respective SGFP. The valve closure/opening time is about 25 s. The valves can either remain fully open or fully closed. At 4000 gpm liquid velocity in the pipe is approximately 26 ft/s. There is an orifice provided in each of the feed pump recirculation lines, which is attached to the condenser and produces a pressure drop of about 455 psi (at 4000 gpm). The pressure drop across the recirculation control valve is about 675 psi and with an addition 20 psi frictional loss in the piping the total pressure drop in the recirculation line is thus 1150 psi. In 1983-1984, spargers were added to the recirculation line which provides additional pressure drop. From this discussion it appears that there is a significant potential for water hammer occurring due to column separation (resulting from control valve closure) in this line.

Several combinations of valve closure cases involving the feedwater regulating (FCV520), isolation (MO2971), and the containment isolation check valve were analyzed by the plant owner. The results indicated that the water hammer loads generated are not detrimental to the FCS piping and supports.

The plant operating experience also shows that the condensate and the feedwater pumps trip/startup has not caused any serious water hammer problems. Following proper maintenance, inspection and testing procedures has prevented leakage from the check valves generally and the containment isolation check valve particularly. A useful safety feature that may be printed out is the provision of an additional motor operated check valve at the discharge of the feedwater pumps.

Severe Transients

Water hammer by Mechanism 1 is not possible in this system because there is no steam discharge into a pool of cold water in this system.

The occurrence of steam generator water hammer (Mechanism 2) incidents has diminished significantly by implementation of the J tubes modification. In the plant B there have been two steam generator incidents (1979 and 1987) that failed the seismic restraints in the feedwater lines of steam generators A and B. After the 1987 incident testing of the containment check valve showed that there was no leakage through it. However, inspection of the "B" steam generator nozzle showed that the annular gap between the sleeve of the feedring and the steam generator nozzle had increased from an initial size of 0.025 in. to about 0.25 in. twelve years later. After the feedring is uncovered this annular gap provides a path for the feedwater to drain out. The empty space will be occupied by the steam. A potential for water hammer Mechanism type 2 will then exists and will be enhanced if the chemistry of water is such that it causes an increase in the gap size of the feedring sleeve. The problem of check valve failure/leakage is always there which may lead to a severe water hammer (3).

The potential for water hammer due to Mechanism 6 exists in both the feedwater and the condensate systems. As shown in Figure 3-4 there are tie lines downstream of both the condensate and feedwater pumps that join the two trains.

When only one train is tripped and if the check valve gets stuck during closure and shuts later against a larger flow rate, this will induce a severe (Mechanism 6) water hammer. This can be avoided by properly maintaining the valve.

Water hammer of the Mechanism 4 type is possible if the heater drains pump is not tripped after the condensate and feed pumps have tripped. The hot water from the heater drains could then be pushed into a low pressure system leading to severe (Mechanism 4) water hammer.

During a cold startup of the plant the system is filled by using the condensate transfer pumps. These are very small (low head and discharge) pumps. These are adequate vents at high points in the system which are left open until it is filled, thereby minimizing the potential for Mechanism 7 type of water hammer.

REVIEW OF OPERATING, TESTING, AND MAINTENANCE PROCEDURES

Condensate Feedwater System

The operating instructions for the Condensate and feedwater systems for plant B discusses the following phases of operation:

- System Filling and Venting
- System Startup
- System Shutdown
- Manipulation of Feedwater of Heater Strings
- System Clean Up

System Filling

The Condensate and Feedwater System is filled by starting both the condensate transfer pumps. The high point vents at various elevations throughout the system are opened. As the system fills the respective vents are closed. When water flows from the vents on top of the flow distribution header the system should pressurize to at lease 50 psig as measured on the feedwater pump discharge pressure indicator. At least one condensate transfer pump is left on to maintain system pressure.

System Startup

The operator is cautioned up front not to start the condensate pumps without filling up the system and pressurizing to 50 psig. The condensate motor is rated for 157 amps at full load. The motor temperatures should be matched while load is greater than 157 amps. The feedwater pump turbine critical speed is 3150 rpm which should not be exceeded. The feedwater pumps should never be operated with less than 4000 gpm. The system operates on only one train up to 50 percent power beyond which the second train is brought into operation.

System Shutdown

The main precaution during this phase of operation is to ensure that the main feedwater pump and the condensate pump go on recirculation as feedwater demand is decreased. When power has reduced to 50 percent (590 MWe gross) the pumps can be removed from service. The condensate pump is stopped first and its discharge valve closed. The heater drain pump in the shut down train is then stopped after which the feedwater pump is tripped. During hot standby the condensate transfer pumps are left on.

Manipulation of Feedwater Heater Trains

The operating instructions precaution that when extraction steam to heaters is being cut out in a trains, the operator should begin from the highest pressure heater and work towards the lowest pressure feedwater heaters. The operator is also precautioned to operate the valve slowly when placing a heater in service. This will prevent rapid thermal transients in the system. The high pressure feedwater heaters (6 and 7) should not be taken out of service until the power level has reached below 95 percent of rated MWe (1,119 MW).

System Cleanup

The main precautions to be observed during system cleanup are:

- The condensate system should be refilled and repressurized with the condensate transfer pumps if for any reason the condensate pump is stopped (tripped) during cleanup.

- The condensate system should not be allowed to "shock". The demineralizer system or the resin coaling in the vessels may be damaged.

The operating instructions give the steps to be followed in order to cleanup the hotwell and the condensate storage tank.

AFW System

The operating instructions for the AFW system give precautions, some of those of interest are listed below.

The service water connection valves must be closed in both the trains to prevent the contamination of Condensate and Feedwater System with service water. The AFW control valves CV3004 (see Figure 3-4) should be slowly closed when the AFW pump low suction pressure alarm is received. The closing is stopped when the alarm clears.

Following a plant trip the operator should take manual control of the plant and maintain the AFW flow rate as constant as possible. If the feedring is uncovered the AFW flow rate should not be allowed to drop below 30 gpm per steam generator. This will prevent the feedring from back leakage. Also, the maximum flow rate should not be allowed to exceed 165 gpm until the steam generator level is restored and the feedring is again submerged.

Periodic Testing

Plant B has various periodic operating test procedures for the Condensate and Feedwater System and AFWS which are described below.

Condensate Feedwater System Tests

The periodic operating test procedure provides instructions for testing the main feedwater check valve. This test is performed to verify valve flapper movement capability. This test is to be performed after each cold shutdown lasting for more than 72 hours. Instructions for testing the high level alarm and the Hi-Level dump features of the feedwater heater and drain tanks are listed in test procedures. This test is conducted monthly when the turbine generator is in operation. Instructions for testing the operating of the bleeder trip valves in the extraction steam supply to the feedwater and condensate heaters are also given. These tests are conducted daily when the main turbine is in operation.

Auxiliary Feedwater System Tests

The periodic operating test procedure for plant B provides instructions for surveillance testing of the steam driven AFW pump, diesel driven AFW pumps and then associated check valves. This test is done every three months. The procedures also provide instructions for "full open" exercising the steam driven AFW pumps steam supply check valves and the pump suction check valves. This test is done annually. Also provided are the instructions for the test to demonstrate the operability of the electric AFW pump. This test is done when the plant is in mode 2 or 3. A different procedure provides instructions for the periodic operating tests conducted for verifying valve line ups. This test is conducted monthly. Instructions for inservice testing of remote or automatically operated valves are given. This test is done every three months. The test for verifying the diesel fuel oil level for the diesel AFW pump is conducted when the plant is in modes 1 to 3.

The instructions for the system performance and valve inservice test specify that the diesel AFW is run for one hour at 1200 rpm while recirculating to the

Condensate Storage Tank. This test is done at each refueling and at least every 18 months. Instructions for performance of the inservice testing of the turbine drives AFW pump steam supply check valves are also given. This test is done after each cold shutdown of duration greater than 72 hours. This procedures also provides instructions for performance of inservice testing of the AFW discharge and suction check valves. In addition this test provides backup verification of proper AFW system design flow, verifies the proper position of AFW discharge valves. These lists are done at each cold shutdown of duration greater than 72 hours. (If the test was not done within 92 days it is not necessary to do this test again.)

Instructions for verifying proper autostart of both AFW pumps every 18 months are also provided.

Maintenance and Inspection Procedures

Discussions with the plant personnel at plant B did not indicate any major maintenance problems with any of the components of the condensate feedwater or the auxiliary feedwater systems.

STRENGTHS AND WEAKNESSES FOR WATER HAMMER PREVENTION

Strengths

Subsequent to Event 3, inspection of the isolation check valves in the 14 in. feedwater line showed that it was in a fairly good condition. The valve was functioning properly by closing after the pump trip and there was no leakage after it has closed. This shows that the isolation check valves are reliable to preclude occurrence of a San Onofre type of event.

Inclusion of a sparger in the feedwater pumps recirculation line helps to reduce the flow variations as a function of the control valve stem position. This tends to improve the stability of the system.

Weaknesses

Occurrence of Event 3 indicated a weakness in the testing and inspection procedures which did not allow for periodic inspection of the gap size between the feedring sleeve and the steam generator nozzle. Inspection of the gap in 1987 showed that after several years the gap size has increased to 0.25 in. compared to a value of 0.025 in. at the time of installation. This is mainly due to corrosion which can be reduced by controlling the quality of feedwater.

Event 3 indicates that the feedwater minimum recirculation line is not adequately designed. The pipe size is small compared to the flow requirements of the line. High flow velocities, resulting from smaller pipe size, increase the potential for water hammer due to the operation of the control valve.

Event 1 cannot recur since the logic for tripping the heater drain pumps has been corrected to trip when the condensate pumps are tripped.

REFERENCES

1. NUREG/CR-2059, "Compilation of Data Concerning Known and Suspected Water Hammer Events in Nuclear Power Plants," 1981.

2. NUREG/CR-2781, "Evaluation of Water Hammer Events in Light Water Reactor Plants," 1982.

3. Van Duyne, D. A., Yow, W., and Sabin, J. W., "Water Hammer Prevention, Mitigation, and Accommodation, Task 2 - Root Cause Analysis for Plant Water Hammer Experience," EPRI RP-2856-3, Task 2 Report, December 1989.

Table 3-1

VALVES DATA

Valve Name	Valve No. Inch	Operator Opening	Size Closing	Stroke Time (s) Velocity (ft/s)		Water	
FW Isolation	MO2971B		Air	14	12.5	12.4	27.5
FW Regulating	FCV520	Air	14	3.2	3.2	27.5	
FW Isolation Bypass		MO2973B	Air	8	3.2	3.2	14.6
FW Regulating Bypass		CV29938	Air	8	2.2	2.2	14.6
AFW Control	CV3004B1	Air	3	18.1	17.9	38.2	
AFW Control	CV3004B2	Air	3	18.8	17.3	38.2	
FW Min. Recirc.	CV2976A,B		Air	8 (at 4000 gpm)	25.	25.	26.0

Table 3-2

STEAM GENERATOR FEED PUMPS
P-101 A&B

Single Stage - Horizontal Centrifugal Pump

Rated Heat: 2020 ft

Rated Flow Rate: 19,800 gpm

Rated Speed: 5200 rpm

Turbine Driven: 13,000 HP

Table 3-3

CONDENSATE PUMPS
P-104 A&B

Eight Stage - Horizontal Centrifugal Pump

Rated Head: 920 ft

Rated Flow Rate: 12,320 gpm

Rated Speed: 892 rpm

Driver: Vertical Solid Shaft Motor, 3590 HP

Table 3-4

AUXILIARY FEEDWATER PUMPS
P-102 A&B

Six Stage - Single Suction Double Volute - Horizontal Pump

Rated Head: 3400 ft

Rated Flow Rate: 880 gpm

Rated Speed: 4560 rpm

Driver - Turbine: 104,555 HP

Table 3-5

LOADS ON SRB DUE TO MECHANISM 2 TYPE WATER HAMMER
INITIAL VOID VOLUME = 20 IN.^{3} (WITH GAP 0.277 IN.*)

Temperature Differential ($T_0 - T_1$) (°F)	Load on Restraint SRB (kips)	Impact Velocity (when void collapses) (ft/s)
20	19.5	6.5
60	32.	10.7
100	38.7	13.
200	47.	15.7
300	49.7	16.7
400	50.4	16.9

*Based on initial slug length = 32 in. and void length = 14 in. (see Figure 3-15).

Table 3-6

LOADS ON SRB DUE TO MECHANISM 2 TYPE WATER HAMMER
INITIAL VOID VOLUME = 5 $IN.^3$ (WITH GAP 0.109 IN.*)

Temperature Differential ($T_0 - T_1$) (^0F)	Load on Restraint SRB (kips)	Impact Velocity (when void collapses) (ft/s)
20	9.7	3.2
60	15.9	5.3
100	19.4	6.5
200	23.5	7.9
300	24.9	8.3
400	25.2	8.4

*Based on initial slug length = 32 in. and void length = 14 in. (see Figure 3-15).

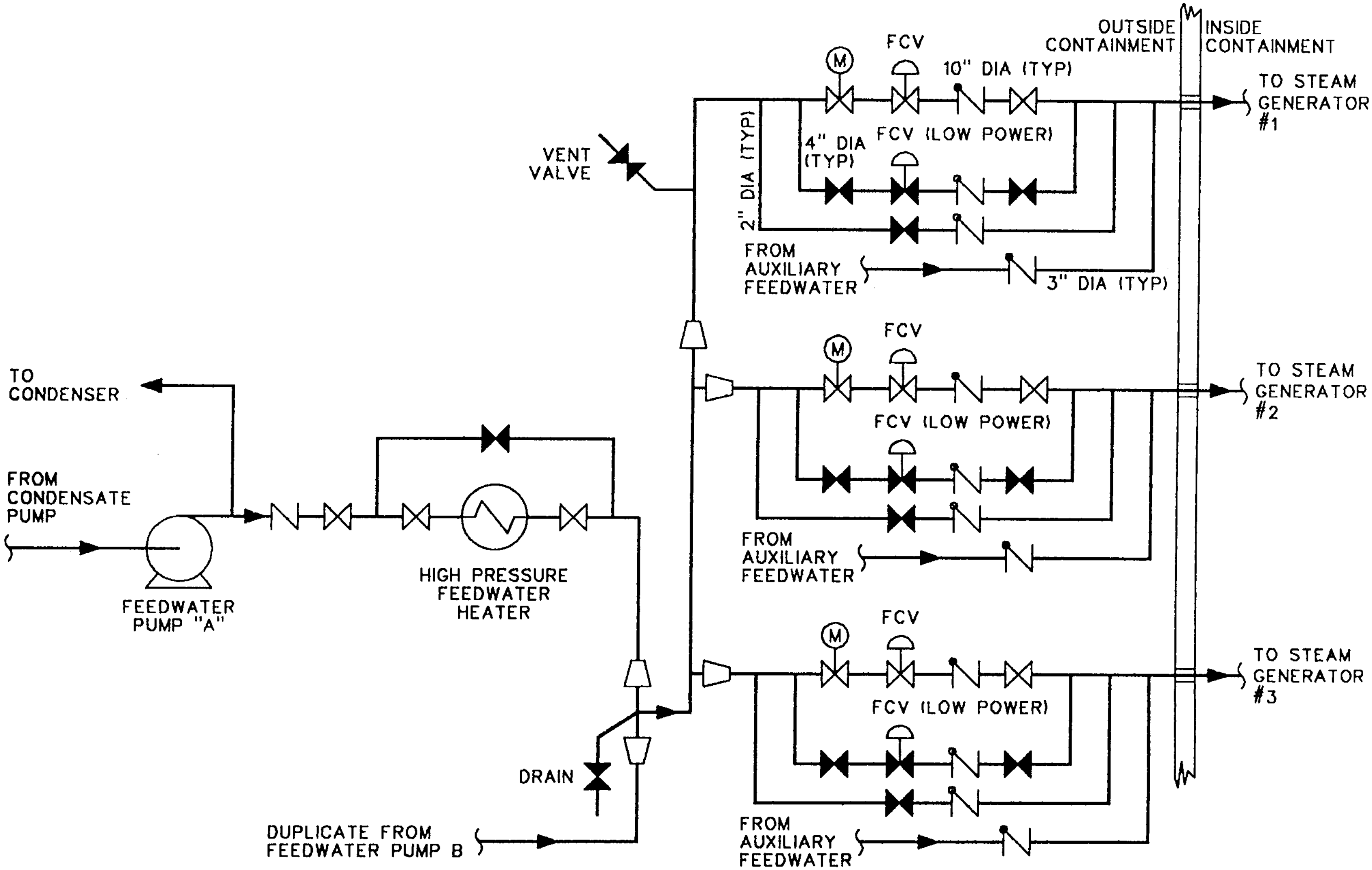


Figure 3-1. Feedwater System Schematic - Full Power (Plant A)

FEED AND CONDENSATE SYSTEM
(SINGLE TRAIN)

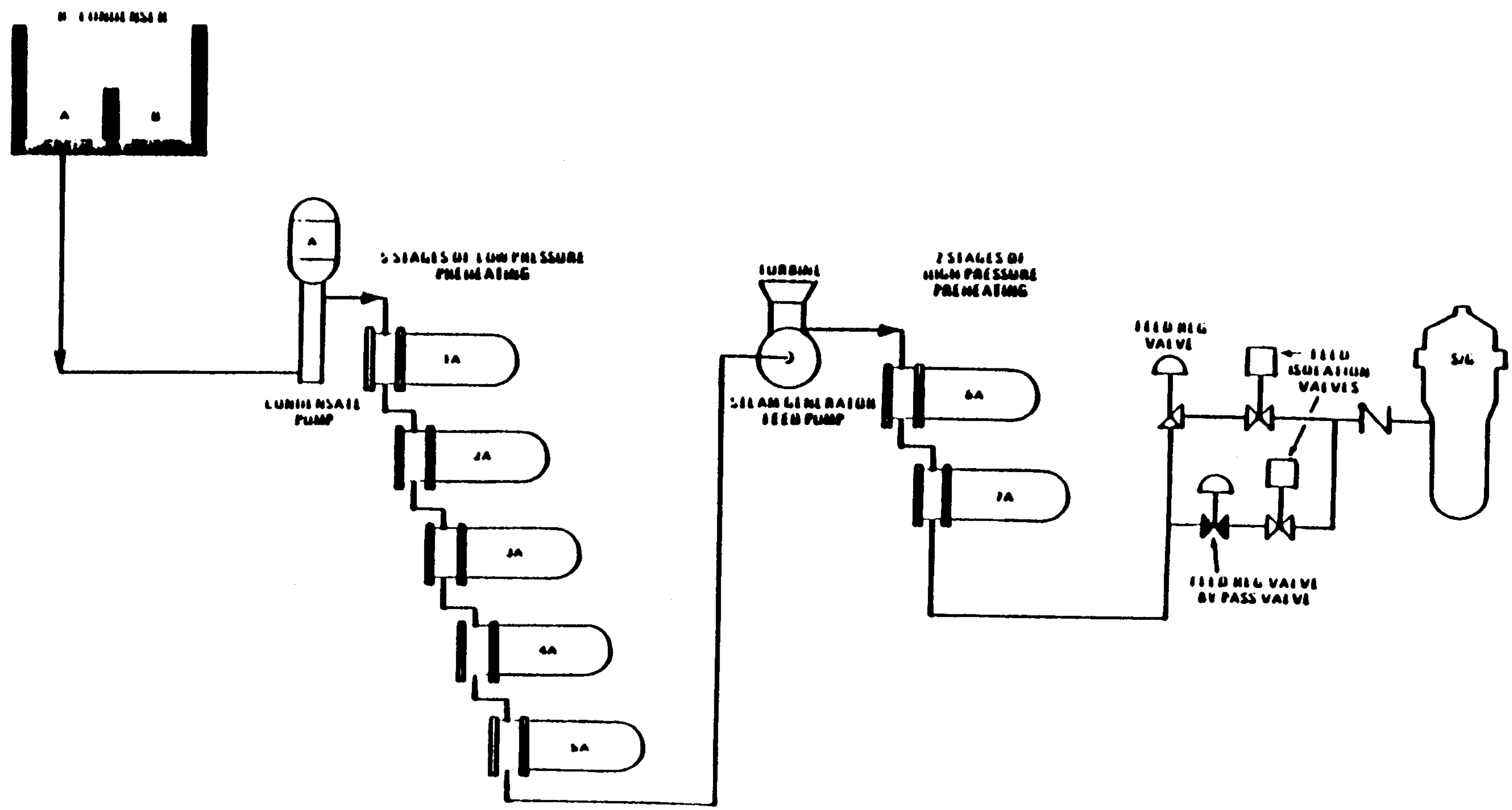


Figure 3-2. Schematic of Condensate and Feedwater System (Plant B)

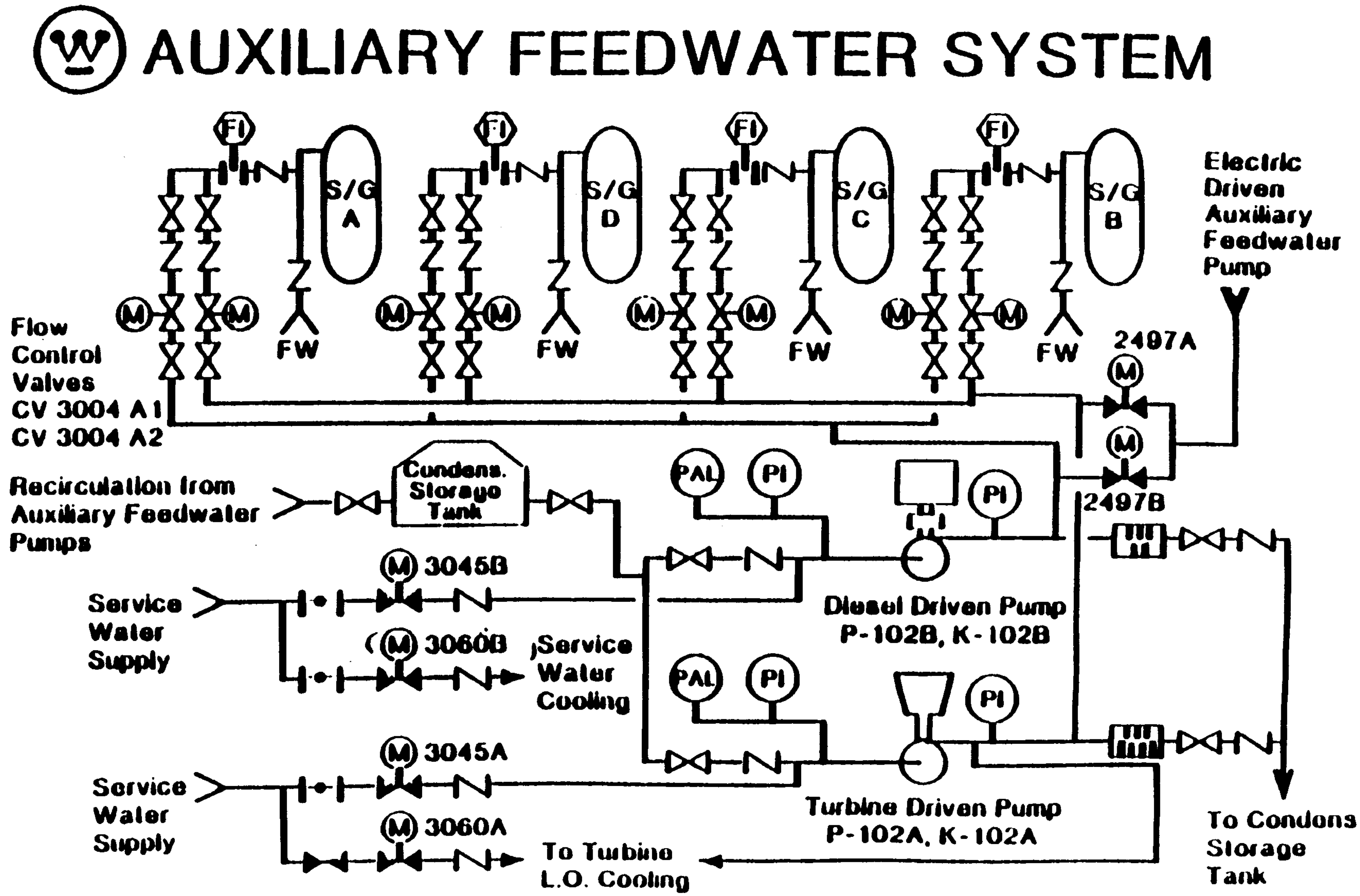


Figure 3-3. Schematic of Auxiliary Feedwater System (Plant B)

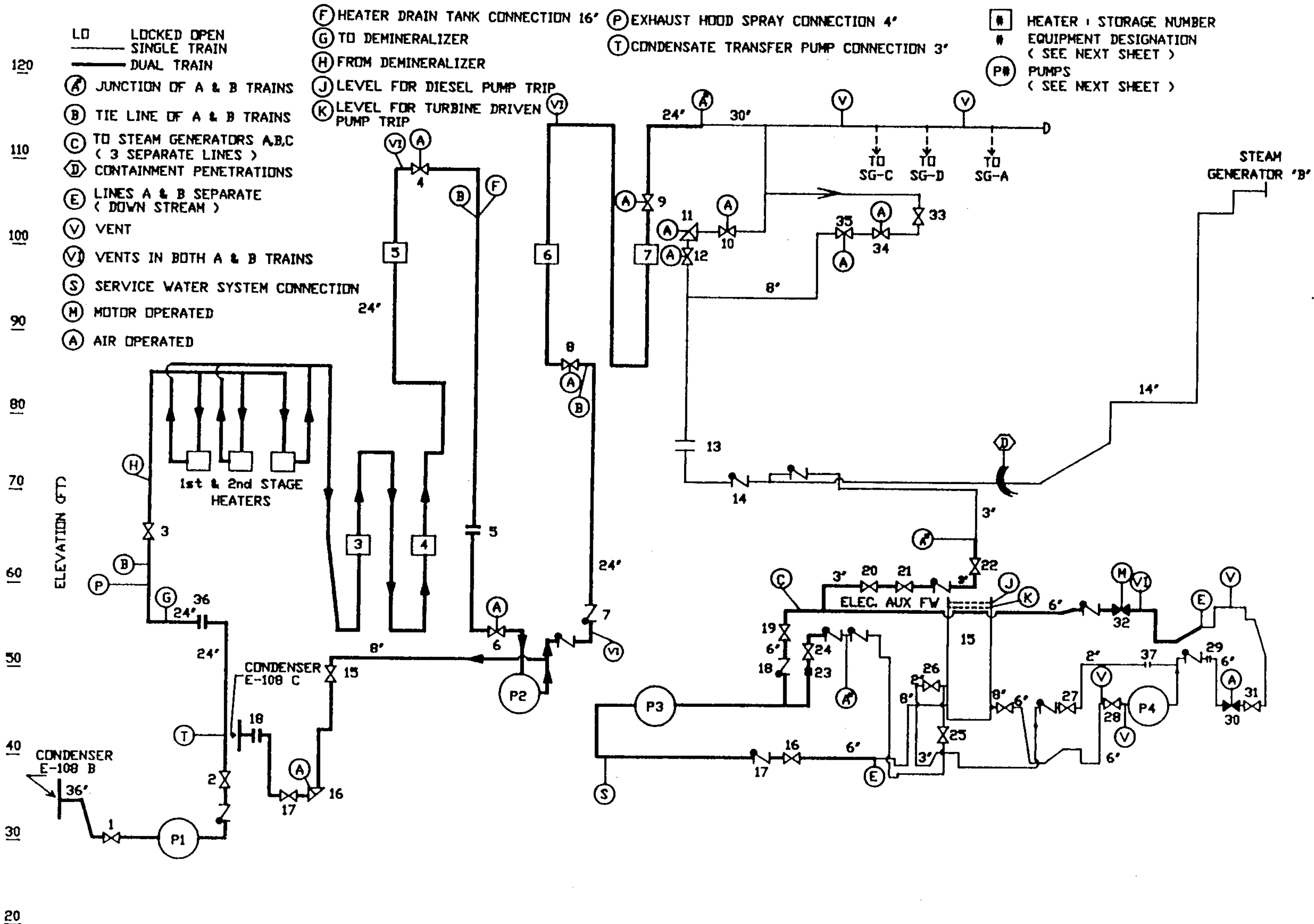


Figure 3-4. Elevation Diagram of the Condensate Feed Water and Auxiliary Feed Water Systems

Nomenclature of Equipment in Figure 3-4

1	Valves CO 001,002
2	Valves MO 2998 A,B
3	Valves MO 7100 A,B
4	Valves CO 009,010
5	Flow Elements FE 2976 A,B
6	Valves FW 001,004
7	Check Valves 2997 A,B
8	Valves FW 019,020
9	Valves FW 039,040
10	Valve FW 055
11	Valve FCV 520
12	Valve 2971 B
13	Flow Element FE 520
14	Containment Isolation Check Valve (Loop B)
15	Condensate Storage Tank T-105
16	Valves FW 112,111
17	Check Valves FW 2027,2029
18	Check Valves FW 2031,2032
19	Valves FW 119,120 (locked open)
20	Valves FW 109,110
21	Valves CV 3004 B1,B2
22	Valves FW 091,087 (locked open)
23	Flow Orifices FO 2986 A,B
24	Valves FW 139,117 (locked open)
25	Valve MD 151
26	Valve MD 160
27	Valve FW 126 (locked open)
28	Valve FW 127
29	Flow Element FE 2957
30	Valve CV 2967
31	Valve FW 128
32	Valves MO 2947 A,B
33	Valve FW 047
34	Valve CV 2993 B
35	Valve MO 2973 B
36	Flow Elements 2972 A,B
37	Flow Orifice FO 2960
P1	Condensate Pumps P-104 A,B
P2	Feedwater Pumps P-101 A,B
P3	Auxiliary Feedwater Pumps P-102 A,B P-102 A Turbine Driven P-102 B Diesel Driven
P4	Electric Auxiliary Feedwater Pump P-182

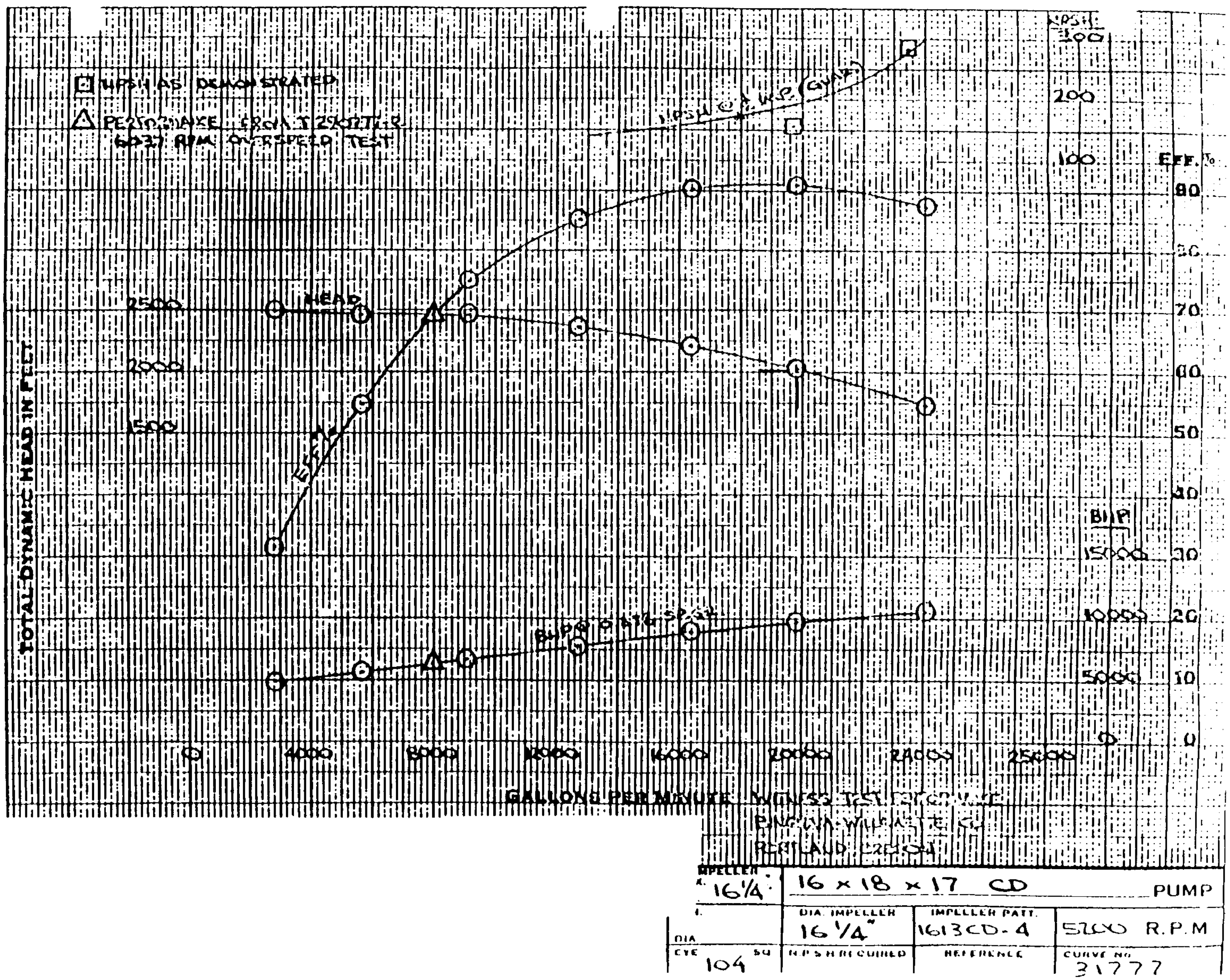


Figure 3-5. Steam Generator Feedwater Pump Characteristics

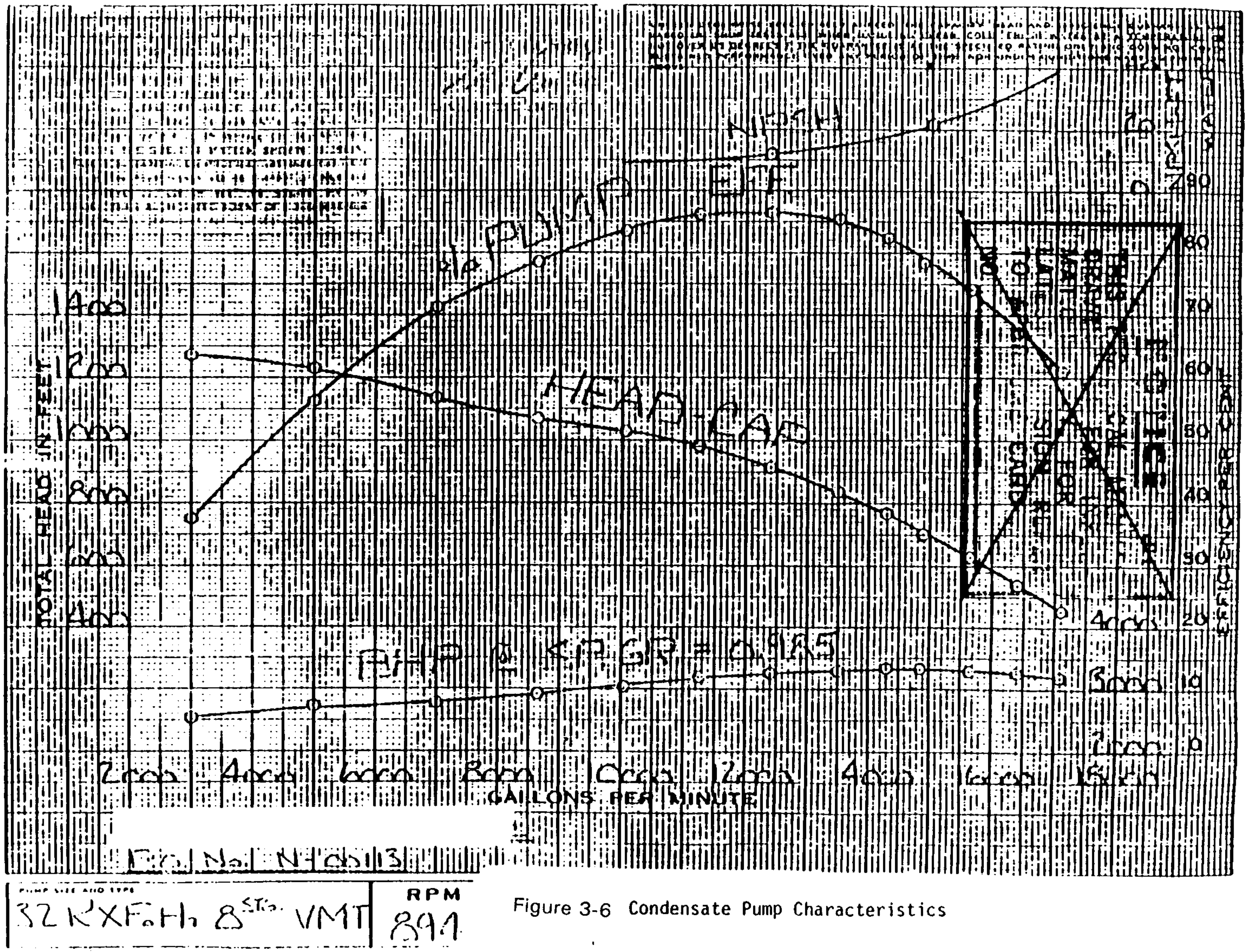


Figure 3-6 Condensate Pump Characteristics

Figure 3-6. Condensate Pump Characteristics

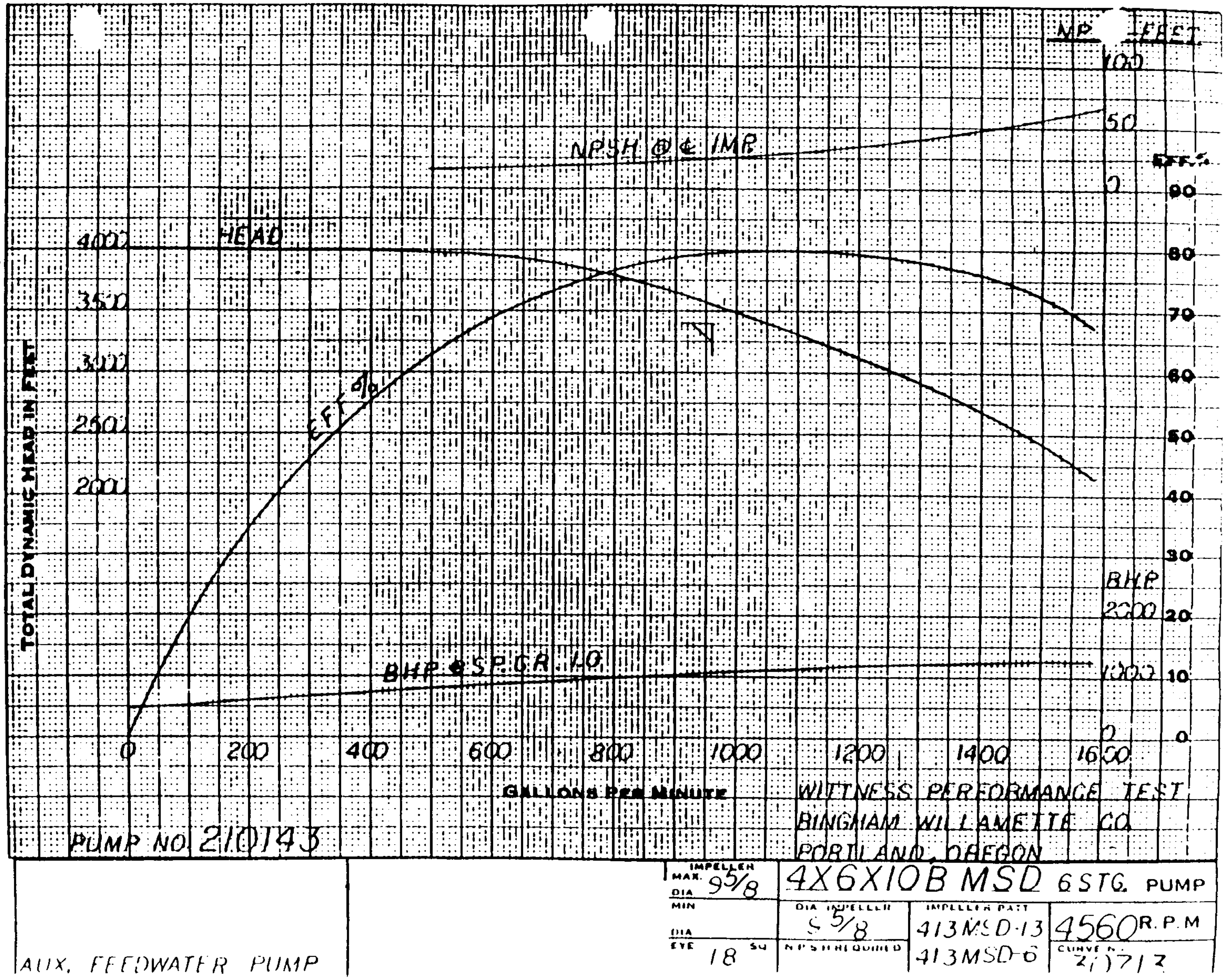
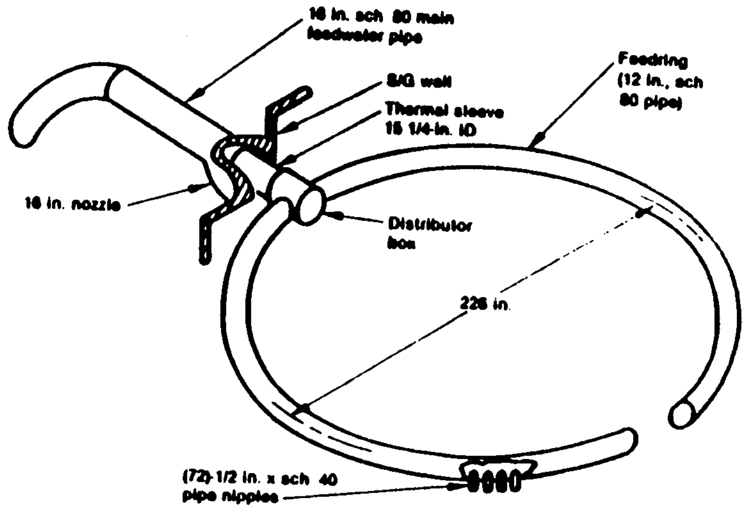
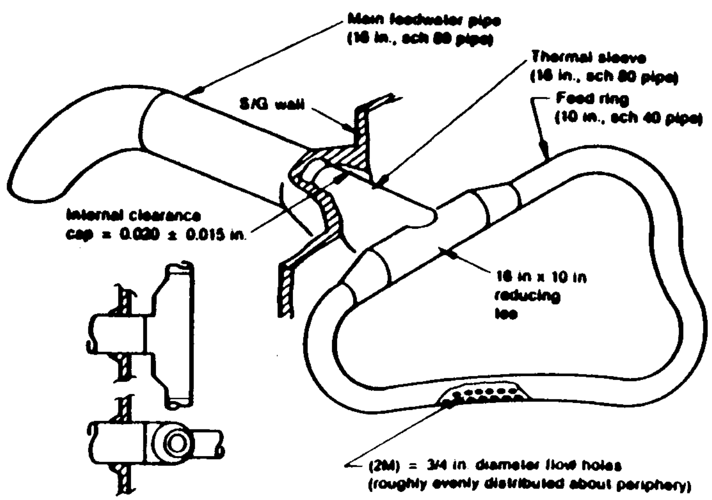


Figure 3-7. Auxiliary Feedwater Pump Characteristics



Combustion Engineering Feedring



Westinghouse Feedring

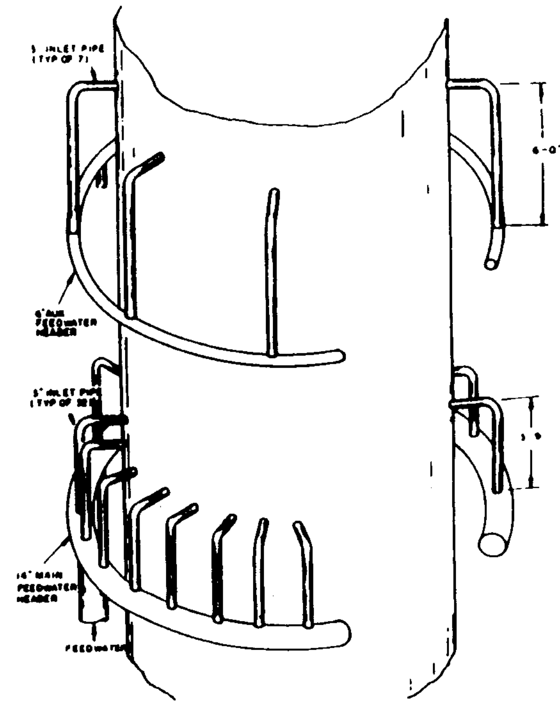

Babcock and Wilcox Feedring

Figure 3-8. Schematic Showing Types of Feedrings

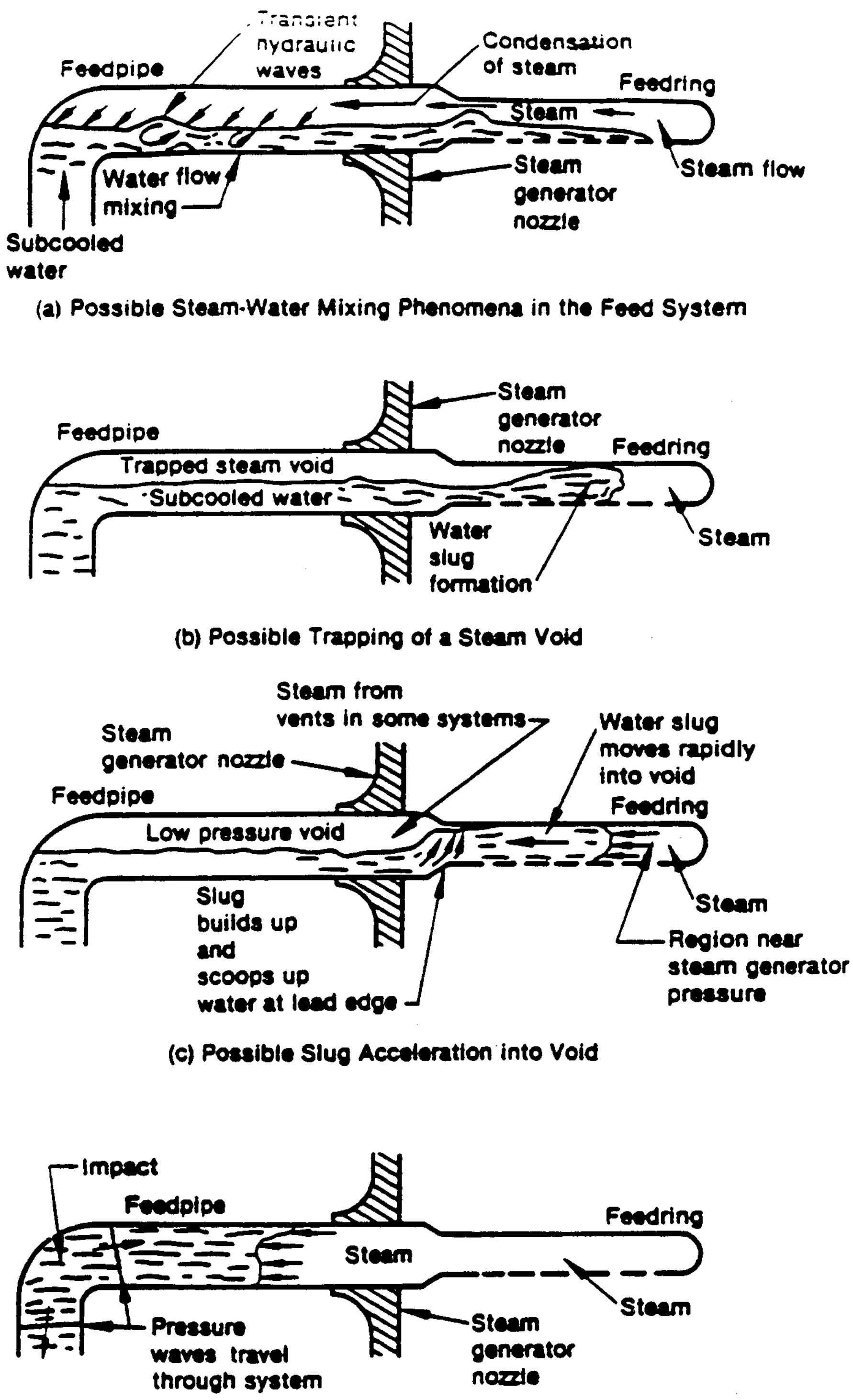


Figure 3-9. Possible Sequential Events Leading to Steam Generator Water Hammer

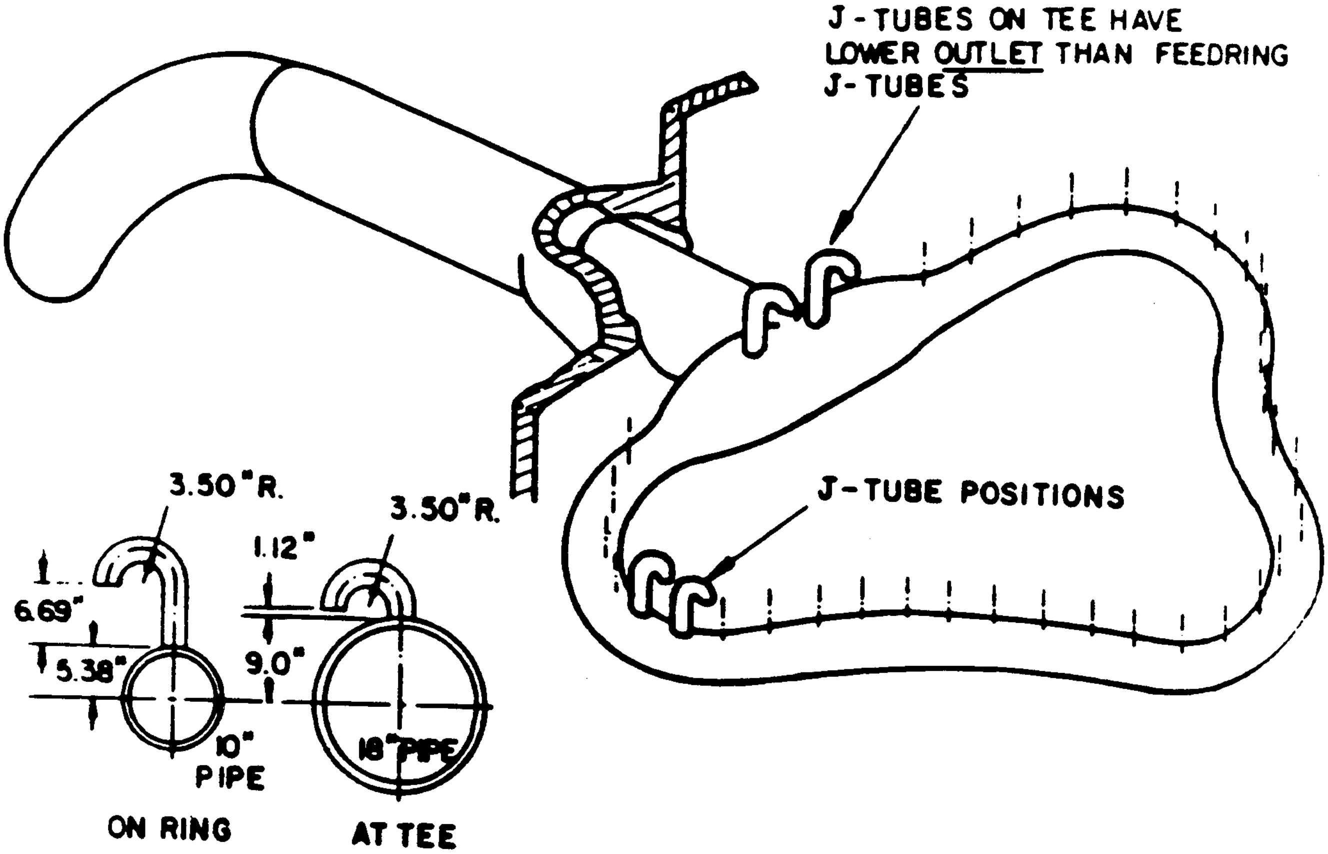


Figure 3-10. J-Tube Feedring Configuration of a Typical Westinghouse Steam Generator

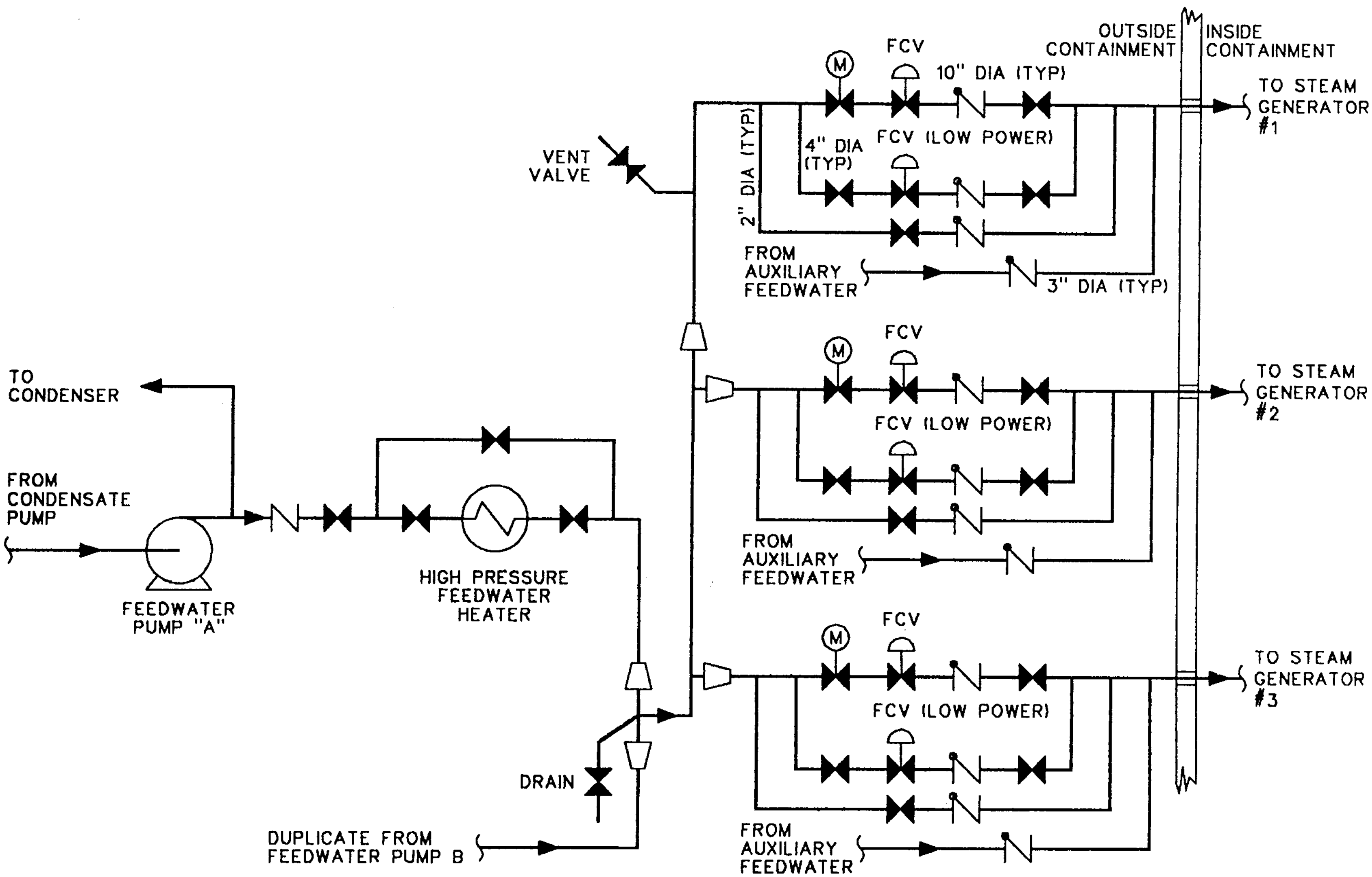


Figure 3-11. Feedwater System Schematic - System Secured (Plant A)

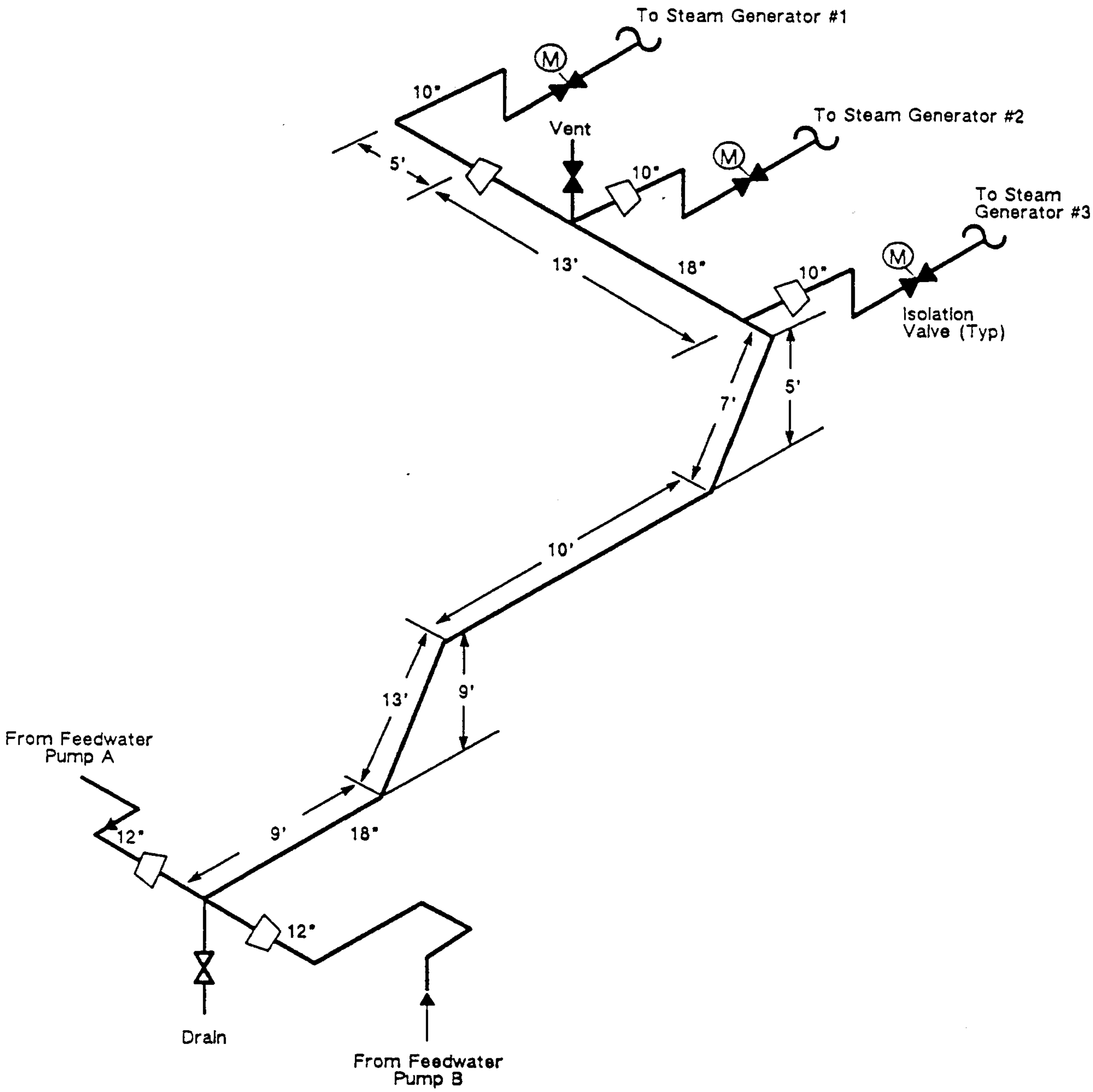


Figure 3-12. Simplified Isometric Diagram for Feedwater System in Area of Water Hammer Event 1

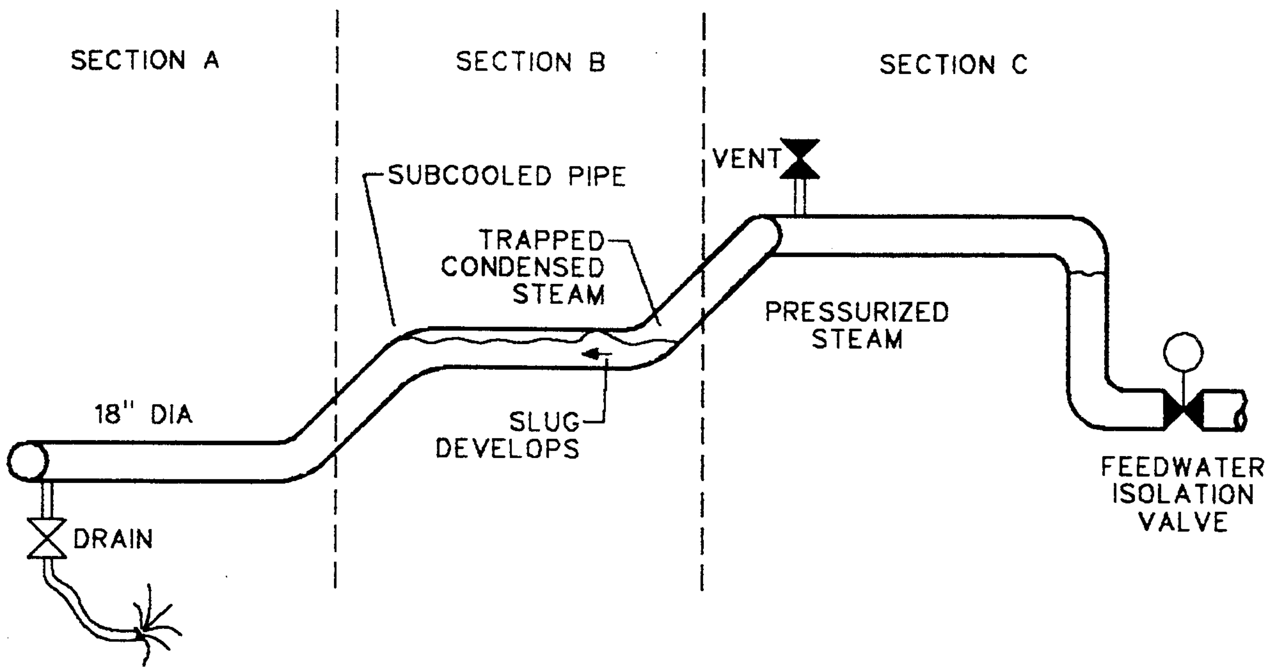


Figure 3-13. Sketch of Mechanism for Water Hammer Event 1

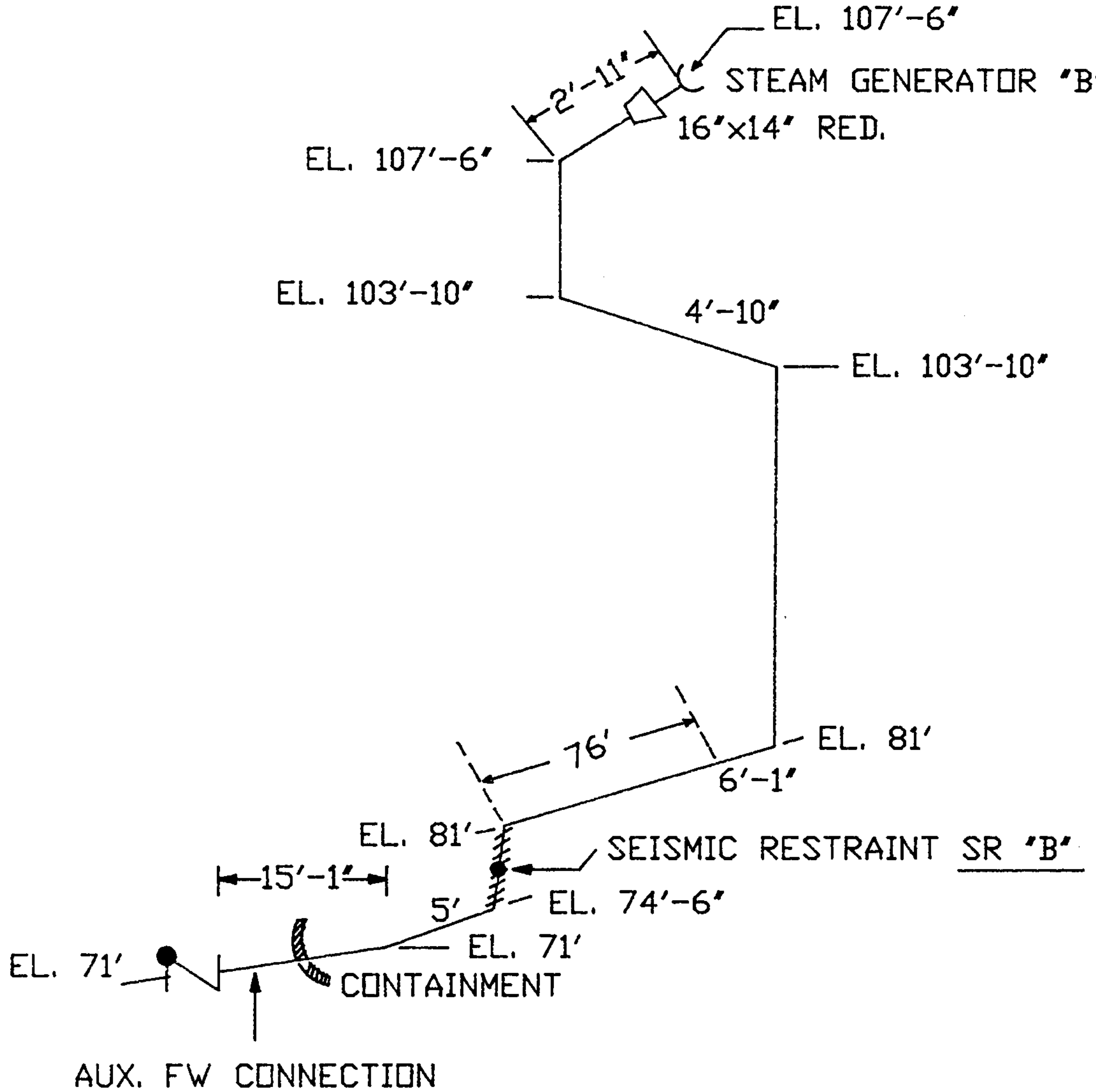
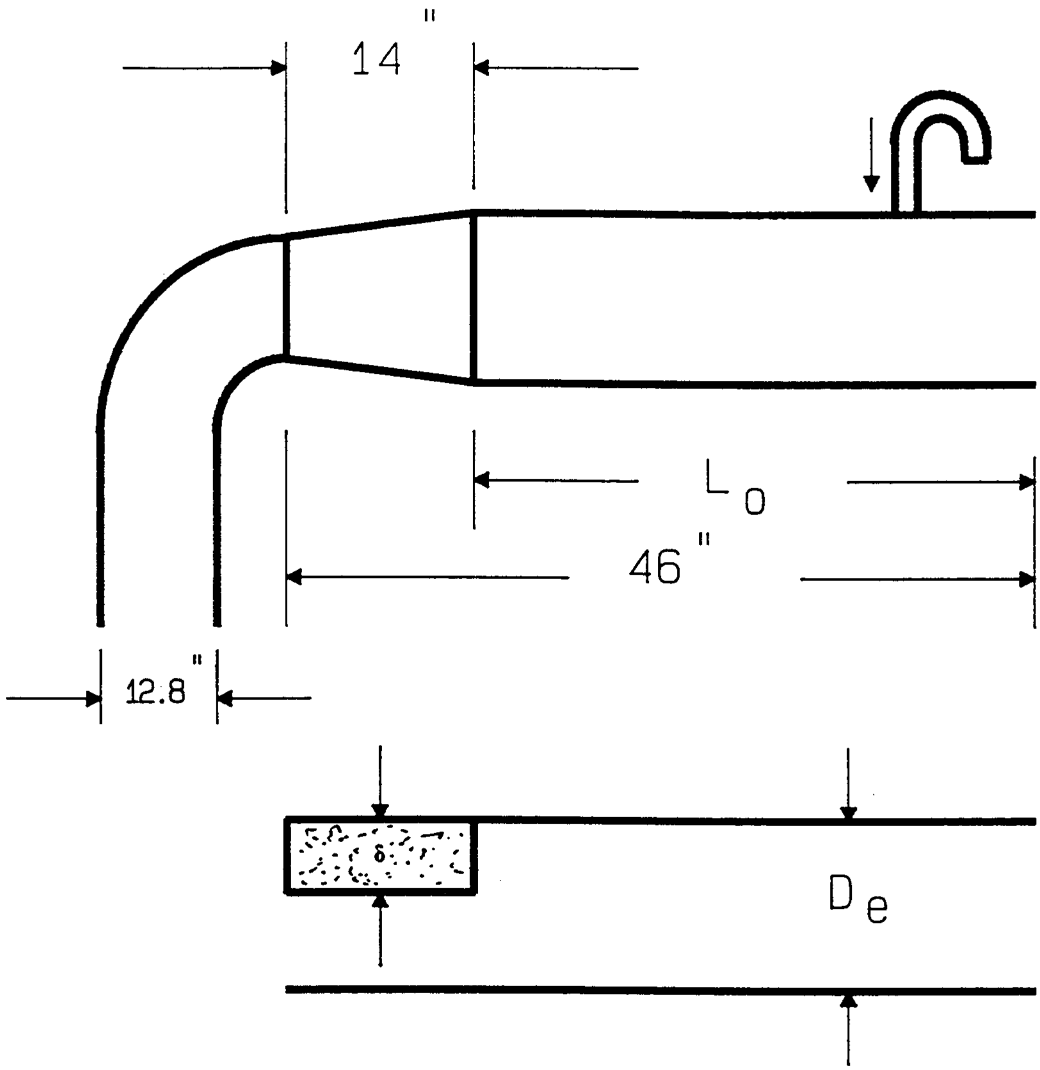


Figure 3-14. Steam Generator "B" Feed Water Line



Initial Slug Length = 32 inches
Total Void Length = 28 inches (14 inches on either side)
Gap = δ based on initial volume

Figure 3-15. Schematic Showing the Geometry of the Feedring Connecting to the Feedwater Pipe

Section 4

HEATER DRAIN SYSTEM IN PWR

SYSTEM FUNCTION

The functions of the heater drain system are to:

- Control the water level in the 1st, 2nd, and 3rd point heaters during normal operating and design transient conditions.

- Collect the cascading effluent from the 1st, 2nd, and 3rd point heaters in a heater drain tank and convey the effluent to the condensate system upstream of the 2nd point heater during normal operating and design transient conditions.

- Convey the effluent from the heaters directly to the condenser via an emergency drain dump line if a high water level exists in the associated heater.

SYSTEM CONFIGURATION, MODES OF OPERATION, AND COMPONENT DATA

Configuration for Water Hammer Event 1

The heater drain system (see Figure 4-1) consists of an arrangement of piping and valves which transports the effluent from the shell of the 1st, 2nd, and 3rd point heaters to the heater drain tank.

There are two strings of heaters. The drains in the first point heater cascade to the second point heater, and from the second point heater to the third point heater. The combined drains in the third point heater are then cascaded to the heater drain tank where the heater drain pump takes suction and injects the drains into the condensate system.

Mode of Operation for Water Hammer Event 1

During this event, the heater drain tank level control system was in operation, maintaining the correct water level in the heater drain tank. However, all extraction steam supplies were isolated because of the turbine trip and the isolation of the turbine stop valve. Figure 4-2 shows the schematic of the third point heater transient dump line. The transient dump line is only used when the third point heater fills to the high level setpoint due to the malfunction of the heater drain tank level control system.

Configuration for Water Hammer Events 2 and 3

The next two water hammer events occurred in another PWR in the high pressure feedwater (FW) heater emergency drain line, while a heat exchanger was being placed in service. Both events resulted in damage to system piping, supports, and components.

The FW system consists of three parallel FW heater trains, each containing one high pressure FW heater and five low pressure FW heaters (see Figure 4-3). Each heater was of the horizontal, closed, two pass type with each having an integral drain zone. These heaters receive steam to preheat the FW from a tap off of the high pressure turbine via the extraction steam system. Drains from the two Moisture Separator Reheater (MSR) drain tanks are directed to the shell of the heater.

The high pressure heater drain system maintains normal water level in the first point heaters during steady state and transient operating conditions. Normal level control is accomplished by cascading the shell side drains to the second point FW heater, which operates at a lower shell side pressure. Level is controlled by an air operated valve (3HDH-LV21A1/B1/C1) as shown on Figure 4-4. In the event of a high water level condition in the first point FW heater, an emergency drain line control valve (3HDH-LV21A2/B2/C2) opens to pass drain flow directly to the condenser to prevent induction of water into the turbine.

Upon actuation of the emergency drain valve control circuitry, the level control valves will modulate to maintain FW heater level within a specified level band.

If the level continues to rise, a Hi-Hi level setpoint will cause the control valve to stroke wide open to protect the high pressure turbine from water induction.

<u>Mode of Operation for Water Hammer Event 2</u>

During this event, it was postulated that a reverse drain flow occurred in the normal drain line between the first and second point heater (lower pressure heater). The first point heater had been taken out of service for maintenance and the water hammer occurred when placing the heater back in service with the plant at operating power. The 2nd point heater was at a pressure of 105 psig, with the extraction steam to the heater secured, resulting in a low 1st point heater shell side pressure.

Due to the abnormal pressure differential, reverse flow was occurring in the normal cascading drain flow path from the 1st point to 2nd point heaters through the level control valve. As the water level in the 1st point heater increased due to abnormal reverse flow from the 2nd point heater, the normal control valve opened wider in response to a 1st point water level increase. The water level then continued to increase, until finally the emergency control valve automatically began to open.

There exists approximately 80 feet of 18-inch piping between the shell side of the 1st point heater and the emergency control valve which directs the water to the condenser. Prior to operation of the emergency control valve it is postulated that a sizeable portion of the water in this line near the emergency control valve was subcooled. The remainder of the fluid up to the 1st point heater was saturated.

As the emergency control valve opened, subcooled water initially passed through the valve at a subcooled fluid velocity followed by the hotter saturated water which flashed and choked when exposed to the low pressure at the valve. This choked flow condition caused an abrupt reduction in fluid velocity from the initially subcooled water velocity to the choked fluid velocity thereby generating a pressure wave which propagated throughout the piping system (see Mechanism 4).

Mode of Operation for Water Hammer Event 3

This water hammer event occurred when bringing the same 1st point heater into service nearly 2-1/2 years after Water Hammer Event 2. Prior to this water hammer event, operators were establishing the emergency drain flow path to the condenser, by manually opening the isolation gate valve upstream of the emergency level control valve. At this point a water hammer occurred, which broke off the valve operator stem along with other pipe and support damage.

It was postulated the line downstream of the valve was either partially or totally voided and filled with vapor due to fluid leakage through the emergency level control valve to the condenser. When the manual isolation valve was opened, the high pressure water rushed into the partially voided line, collapsing the vapor pocket, and thereby generating a Mechanism 3 type water hammer.

Component Data

The major active components in the heater drain system in a PWR power plant are:

- Heater drain pump
- Heater drain tank supply check valve
- Heater drain tank high level dump valve
- Heater drain pump mini recirculating valve
- Heater drain tank level control valve
- Heater high level switch
- Heater transient dump valve
- Heater drain tank level switch

Selected data are noted in the Water Hammer Experience subsection for the heater drain systems investigated.

WATER HAMMER EXPERIENCE

In the 1970's a significant number of water hammer events were reported in LWR power plants. This is so, because many power plants were built and began commercial operation in this time period.

Each event was analyzed in the Task 2 Root Cause Report (1) to determine the areas of each system which are prone to water hammer, the specific water hammer mechanism, and root cause. The remedial actions taken by the utility to preclude future occurrence of a similar water hammer were described. Appendices A and B of (1) presented the BWR and PWR utility water hammer databases and Appendix C therein listed the utility plant codes used. Areas prone to water hammer were identified in typical schematics of each system discussed.

It has been determined that a cause of water hammer in heater drain systems is hot water entering a low pressure line (low pressure discharge).

The procedural and engineering factors contributing to the above occurrence of this type of water hammer are:

- A lack of awareness concerning the possibility of water hammer events, their causes, and potential damages

- A lack of information available to the operator concerning the conditions in the system, to allow for proper action

- Inadequate design considerations for potential water hammer

Three events that have occurred in heater drain systems at PWR power plants are briefly discussed below:

WATER HAMMER EVENT 1: THIRD POINT HEATER TRANSIENT DUMP LINE ISOLATION VALVE OPERATION

Approximately twenty minutes after a turbine trip with the main feedwater pumps re-started to run in the recirculation mode back to the condenser, operators observed pipe vibration and noise in the third point heater transient dump line. As witnessed by plant personnel, the event occurred following the opening of the third point heater transient dump valve. Upon inspection, it was determined that the water hammer caused both pipe denting and pipe restraint damage. The locations of the damaged pipe and restraint are identified in Figures 4-5 and 4-

6. Figure 4-5 provides an isometric view of the transient dump line. Figure 4-6 provides a more detailed description of the pipe damage and the pipe movement which caused the damage.

The transient dump line operates only when the water level in the third point heater reaches the high level setpoint. This indicates that the normal drain path to the heater drain tank is unavailable due to closure of the drain line check valve.

<u>Mechanisms Responsible for the Event</u>

The water hammer mechanism which is responsible for the damage observed for this portion of the heater drain system is Mechanism 4 of the water hammer mechanisms as described in Section 2. Under this mechanism, the hot water flashes when exposed to the lower pressure downstream of the dump valve, resulting in a "choked flow" condition which limited the flow through the valve. The water hammer occurred as the fluid velocity abruptly changed from the initial subcooled velocity to the reduced "choked" velocity which generated a significant pressure wave which propagated throughout the piping system.

<u>Scenario of Events</u>

The third point heater utilizes the drains from the second point heater, extraction steam from the low pressure turbine, and vented steam from the steam generator blowdown flash tank to heat the condensate after it leaves the fourth point heater.

After a turbine trip, extraction steam to the first, second, and third point heaters, and all tanks draining to the first and second point heaters, are isolated. The steam generator blowdown flash tank vent is redirected to the condenser. The drains from the first and second point heaters will continue to cascade to the third point heater until their level control valves isolate on the lower limit of their control range.

Furthermore, when extraction steam to the third point heater is closed with continued feedwater tube side flow in circulation, the operating pressure in the heater decreases sufficiently below the pressure in the heater drain tank to shut the check valve in the drain line to the heater drain tank. The closure of the check valve isolates the heater drain pump from the transients being considered. The pressure in the heater drain tank does not drop as rapidly as it does in the third point heater, even though they are connected by a small (4-in. dia) equalizing line. This vent line is sized to prevent the heater drain tank pressure from decaying too rapidly during a normal step load reduction in power which would cause the heater drain pump to cavitate. However, the vent line is inadequately sized for such a rapid transient as a turbine-trip event. It is this system response which allows the third point heater level to rise up to the transient dump level setpoint and subsequently open the transient dump valve to discharge water in the third point heater directly to the condenser.

Description of Water Hammer

Prior to the turbine trip, cold water (about 70°F) collects in the transient dump line upstream of the transient dump valve due to condensation in the uninsulated pipe line. It is estimated from the piping configuration that this cold water length under normal operating conditions could be as long as 100 ft upstream of the transient dump valve. Under normal operation, the water level in the third point heater drain line is below the branch connection to the 20-in. transient dump line as shown in Figure 4-2. When the water level in the third point heater drain line rose to an elevation higher than the branch connection to the transient dump line after the turbine trip, hot water would fill up the void space behind the cold water in the dump line. The hot water (about 200°F) was saturated in the third point heater and slightly subcooled in the region where the hot water contacts directly with the cold water. The pressure at the inlet to the dump valve was calculated to be approximately 29 psia, assuming that the shell side pressure in the third point heater had been reduced sufficiently to atmospheric pressure.

When the transient dump valve opened on the high level signal in the third point heater, the cold water would be discharged into the condenser followed by the hot water. Modest depressurization waves generated by the valve opening propagated upstream along the transient dump line toward the heater. The transient dump valve is a 16-in. diameter ball valve designed to open quickly when called upon to release the excess water accumulated in the third point heater, thus avoiding flooding the low pressure turbine after tripout. It was estimated that the transient dump valve could discharge approximately 30,000 gpm cold water when wide open, which is equivalent to a 32 ft/s velocity in the 20-in. diameter pipe. This flow rate would be reduced when the valve had cleared the cold water and started discharging hot water. The flow reduction was caused by flow choking at the valve outlet when the hot water flashes into a saturated steam-water mixture. Under this condition, the flow rate of hot water passing through the valve would be reduced to approximately 22,000 gpm, which is equivalent to a 25 ft/s flow velocity for the water column immediately upstream of the dump valve. The calculated differential flow velocity (ΔV=7 ft/s) represents the maximum velocity difference under the specified different temperatures of 70°F and 200°F. Even a portion of this velocity difference would have generated significant pressure waves which caused the damage, noise, and vibration identified by the plant personnel.

Limiting Dynamic Load Estimate

The water hammer caused denting to the 20-in. diameter pipe (Schedule 20) and the pipe support as shown in Figure 4-6. A PSA snubber was damaged along the transient dump line. The pipe was damaged with a dent size of about 10 in. high, 6 in. wide and 2 in. deep. The lateral web of the support flange (WF 6 in. x 25 in. x 1 ft-8 in.) was also damaged; however, no information was available on its damaged condition. Based on this limited information, only a very rough estimate can be made as to the magnitude of the pressure waves generated.

The failed snubbers were designed for a load capacity of 21.6 kips. However, the test results conducted in the vendor's laboratory indicated that the devices had been overloaded considerably by forces up to 31.6 kips in order to duplicate the observed damage. Similar magnitudes of loads were also estimated for the pipe restraint failure by considering the strain energy in the piping and support deformation. According to the total energy absorbed by the deformation of the pipe without considering the energy absorption by the support flange deformation, the maximum pipe restraint load was calculated to be approximately 33 kips, using a Stone & Webster local pipe indentation program. These loads were generated by a water hammer pressure wave when the steam bubble collapsed as was described previously.

Based on the pipe length and the pipe support location, the magnitude of the fluid dynamic force due to the Mechanism 4 type of transient was estimated to be roughly 27 kips in order to generate 33 kip load at the support. This force is approximately equal to an 87 psi pressure wave for a 20-in. diameter pipe. According to the Joukowsky elastic wave theory, the pressure wave (ΔP) is related to the relative velocity (ΔV) when the bubble collapses as follows:

$$\Delta P = 0.5 \rho a \Delta V$$

where ρ is water density in slug/ft^3 (about 57.3 lb/ft^3 for 200°F) and a is the wave speed in ft/s (about 3,850 ft/s). The factor 0.5 is included to account for the effect of wave propagation in both directions after the impact. This impact velocity was estimated to be approximately 3.4 ft/s, which is within the range of the maximum velocity difference caused by the choke flow at the transient dump line discharge under the temperature differential as previously described.

Water Hammer Root Causes

Based on the above-described scenario and evidence, the root causes to this event are attributable to the following design issues:

- Inadequately sized vent line contributes to the unbalanced pressures between the third point heater and the heater drain tank, and consequently, initiates dump flow in the transient dump line

- Existence of subcooled water followed by saturated water in the transient dump line prior to valve opening created the conditions necessary for a low pressure discharge water hammer - Mechanism 4

Corrective Measures

The most effective means to prevent this event from recurring is to provide an adequately sized heater drain tank vent line to the third point heater. The size of the vent line should be optimized not only for proper venting capacity during transient conditions to avoid frequently actuating the dump valve, but also for maintaining adequate pressure in the heater drain tank and sufficient NPSH for the heater drain pump during normal operating conditions.

An option to mitigate this event which the utility adopted was to revise the transient dump line control scheme that allows for a slower opening dump valve. A slower flow rate when the subcooled water transitions to saturated water at the dump valve will mitigate this transient. However, care must be exercised to ensure that the slower valve opening time does not compromise the original objective of the transient dump line which is to prevent excessive water accumulation in the third point heater and avoid flooding the low pressure turbine. This can be satisfied by properly readjusting the high level controls setpoint.

WATER HAMMER EVENT 2: FIRST POINT HEATER TRANSIENT DUMP LINE EMERGENCY CONTROL VALVE OPERATION

Description of Events

This water hammer occurred in the early evening with limited information as to the conditions in the piping system that may have contributed to the event. The 1st point heater had been taken out of service for maintenance. The transient occurred when Operations Personnel were placing the heater back into operation with the plant at power. The 2nd point heater was at a pressure of 105 psig. The extraction steam flow to the 1st point heater was secured, resulting in a low first point heater shell side pressure. Because of the abnormal pressure differential, reverse flow was occurring in the normal cascading drain flow path from the 1st point to the 2nd point heater through the normal 1st point heater level control valve.

As the level in the 1st point heater increased, the normal level control valve opened more in response to a 1st point heater level increase. As the water level continued to increase, the emergency drain control valve began to open.

There exists approximately 80 ft of 18-in. piping between the shell side of the 1st point heater and the emergency control valve which directs the water to the condenser. Prior to operation of the emergency control valve it is postulated that a sizeable portion of the water in this line near the emergency control valve was subcooled. The remainder of the fluid up to the 1st point heater was saturated.

The postulated fluid transient scenario is that the emergency drain control valve began to open in response to a rising level in the 1st point heater. The initially subcooled water in the pipe passed through the open or partially open valve followed by saturated hot water. The hot water began to flash when exposed to the lower pressure downstream of the valve, resulting in a "choked flow" condition which limited the flow through the valve. The water hammer occurred as the fluid velocity abruptly changed from the initial subcooled velocity to the reduced "choked" velocity which generated a significant pressure wave which propagated throughout the piping system.

Extent of Damage

Visual inspection of the piping system after the event indicated that the piping moved approximately ± 8 in. in an axial direction as shown in Figure 4-7, resulting in a permanent deflection of 1-1/2 in. to 2 in. from the original piping location. The damage in the main run piping consisted of dents in the intrados region of two elbows, due to the impact with the concrete corners of the pipe chase. The yoke of the emergency drain control valve broke off, and the valve body and internals were deformed. Branch lines off the main run were deformed; adjacent fire protection piping was deformed and broken; and adjacent pipe supports were broken. The concrete was also spalled in the area where the main piping impacted.

A liquid penetrant test was performed at critical locations on the drain piping. No cracking was evident. Surface defects were identified but were attributed to fabrication and/or construction processes and were not considered deleterious to the material.

The worst dent was characterized by a smooth transition along the intrados of the elbow approximately 1 in. deep and 8 in. in diameter with no sharp discontinuities or folds.

Limiting Dynamic Load Estimate

Damage occurred to piping components in this event due to a passive water hammer caused by a mass flux change between subcooled and hot water at a valve discharging to a condenser. Figure 4-7 is a schematic of one such piping system. Table 6-3 (Task 5 - Assessment Guidelines (2)) is used to predict the Joukowsky pressure rise in the upstream pipe based on the following initial conditions:

operating pressure:	181 psig
hot operating temperature:	380° F
upstream pipe ID:	17.25 in. (majority of piping is 18 in. nominal)
valve ID:	6 in.

The matrix intersection of the 200 psia - 380°F entry in Table 6-3 is 2779 psi. Therefore, the upstream pressure rise is about 2779 (0.121) = 336 psi (for a 6 in. to 17.25 in. valve to pipe ID ratio) resulting in a peak pipe segment load of approximately 79 kips in an 18-in. pipe based on the Joukowski elastic wave theory equation. Pipe damage was reported as noted in Figure 4-7.

Corrective Action

Subsequent to this water hammer event, a revision was made to the operating procedure to provide for placing a high pressure heater in service with the plant at power. Previous to the event, there was no procedure in place for this abnormal system configuration. The procedure included steps to equalize the shell side pressure in the startup heater with an operating high pressure heater via a common vent prior to establishing any drain flow paths.

This step was taken to insure that normal pressure conditions existed in the respective heater prior to allowing any drain flow, therefore eliminating any potential for reverse flow which is thought to have caused this transient by creating high water levels in the 1st point heater. This procedure revision did not take into account the effect of the initially subcooled water near the valve and the relatively high energy fluid upstream of the subcooled water in the emergency drain piping.

WATER HAMMER EVENT 3: FIRST POINT HEATER TRANSIENT DUMP LINE ISOLATION VALVE OPERATION

Description of Events

This water hammer event occurred when Operations Personnel were in the process of bringing the same high pressure heater in-service with the plant at power nearly 2 1/2 years later than the previous water hammer Event 2 described above. At the time of the transient, operators were establishing the emergency drain path to the condenser in accordance with the operating procedure (the emergency drain control valve at this point is closed and in manual operation). The operator was opening the upstream isolation gate valve (see Figure 4-8) when the event occurred. The water hammer transient caused a pipe displacement of such a magnitude that the emergency control valve operator broke off as did the handwheel of the manual isolation valve.

It was postulated that the downstream emergency drain control valve leaked fluid to the low pressure condenser creating a vapor pocket between the manual isolation valve and the closed emergency control valve. Therefore, condenser pressure with water vapor existed immediately downstream of the manual isolation valve with high pressure water upstream of the valve. When the operator manually opened the isolation valve, the fluid rushed into the partially or totally voided piping collapsing the vapor bubble (a Mechanism 3 type water hammer) which generated a significant pressure wave which propagated throughout the piping system.

Extent of Damage

Damage assessment subsequent to this event showed that two small bore branch lines off the main piping in the vicinity of the emergency drain control valve were permanently deformed due to impact with structural steel. Once again, the pipe elbow impacted the concrete corner of the pipe chase, further enlarging the previous dent.

The valve operators which were damaged were repaired. Two pipe supports located in the pipe trench, designed as sliding deadweight supports, were severely damaged when the pipe saddle was pushed off the support steel as the pipe moved in one direction and subsequently ripped out the supports when the pipe moved in the opposite direction.

A magnetic particle examination was performed on the dent at the elbow, on the socket welded joints on the deformed branch line, and on the pipe-to-shell welds at the feedwater heater and condenser revealed no significant damage to the pressure boundary.

Corrective Action

Subsequent to this event, the startup procedure was further revised to allow for a temporary hose connection from the condensate system to the emergency drain piping. The purpose of the connection was to allow for filling of the drain piping with lower temperature condensate. The intent was to reduce the saturation pressure of the fluid and eliminate the potential for void formation in the piping between the manual isolation valve and the emergency control valve (see Figure 4-8).

Implementation of the recommended procedural change and vent line fix has eliminated any further water hammers on this system at this time. Operations personnel have indicated that the emergency drain control valves have actuated and functioned properly during normal plant operation, although there is ongoing concern that not all potential water hammer events have been eliminated.

SYSTEM EVALUATION

Normal Transients

There are no expected transients that heater drain systems are typically designed for such as pump start-up or rapid valve actuation. However, the system design does consider temperature and pressure conditions for all flows to minimize undesired flashing.

Severe Transients

Hot saturated water entering a low pressure line is the most common cause of water hammer in this system. This piping system is not normally designed to withstand this type of water hammer.

Sequences of valve operation typically assume non-leaking valves prior to their operation. For example, a leaking valve adjacent to the condenser allowed steam vapor to form between two normally closed valves. A severe water hammer event occurred when the upstream valve was manually opened as discussed in Water Hammer Event 3.

REVIEW OF OPERATING, TESTING AND MAINTENANCE PROCEDURES

Operating procedures

Water Hammer Event 1 may be mitigated if operating procedures include instruction on limiting the flow rate through the transient dump line after a turbine trip, while simultaneously efficiently removing accumulated water in the third point heater.

Water Hammer Events 2 and 3 may be mitigated by (1) the previously described revision to the operating procedures, where the 1st point heater shell side pressure remains higher than the 2nd point heater pressure when bringing the 1st point heater into service, and (2) adding the drain line so that the piping between the manually operated isolation valve and the emergency control valve does not void and remains full, respectively.

Testing procedures

The transient dump line for all three water hammer events is an infrequently used emergency backup system that prevents excessive accumulation of water in the heater, and as such is not tested for the possibility of water hammer occurrence for this particular mode of operation.

Maintenance Procedures

There were no maintenance or inspection procedures observed for these water hammer events, for the same reason as described in testing procedures above. If level indicators and temperatures elements were present to detect line voids or cold/hot water interfaces, regular inspection procedures for this system would provide plant personnel with enough information to identify if conditions are right for a potential water hammer occurrence.

STRENGTHS AND WEAKNESSES FOR WATER HAMMER PREVENTION

Strengths

One strength observed during the investigation of water hammer events on the first point heater drains was the use of a procedure to avoid the possibility of an inadvertent water hammer. That was to fill the drain piping with cold water prior to sequencing the valves in the emergency dump line to the condenser to automatic operation. This procedure, even though very fundamental, worked well in this application.

Weaknesses

- The 3rd point dump line needs to be optimally sized to pass all flows during normal and transient modes of operation of the heater drain system.

- The U-shaped loop at the transient dump valve to the condenser for Water Hammer Event 1 is undesireable (see Figure 4-5). The dump valve is located lower than the inlet nozzle to the condenser. The valve should be located above or at the same elevation as the condenser nozzle to avoid formation of subcooled water columns.

- Subcooled water and hot saturated water normally co-exist in the infrequently used heater drain emergency backup dump lines to the condenser. Passive water hammers are still likely to occur, unless temperatures are equalized in the line prior to operation.

REFERENCES

1. Van Duyne, D. A., Yow, W., and Sabin, J. W., "Water Hammer Prevention, Mitigation, and Accommodation, Task 2 - Root Cause Analysis for Plant Water Hammer Experience," EPRI RP-2856-3, Task 2 Report, December 1989.

2. Van Duyne, D. A., Sabin, J. W., and Rooney, J. W., "Water Hammer Prevention, Mitigation, and Accommodation, Task 5 - Water Hammer Assessment, Prevention, and Diagnostic Guidelines," EPRI RP-2856-3, Task 5 Report, October 1990 draft report.

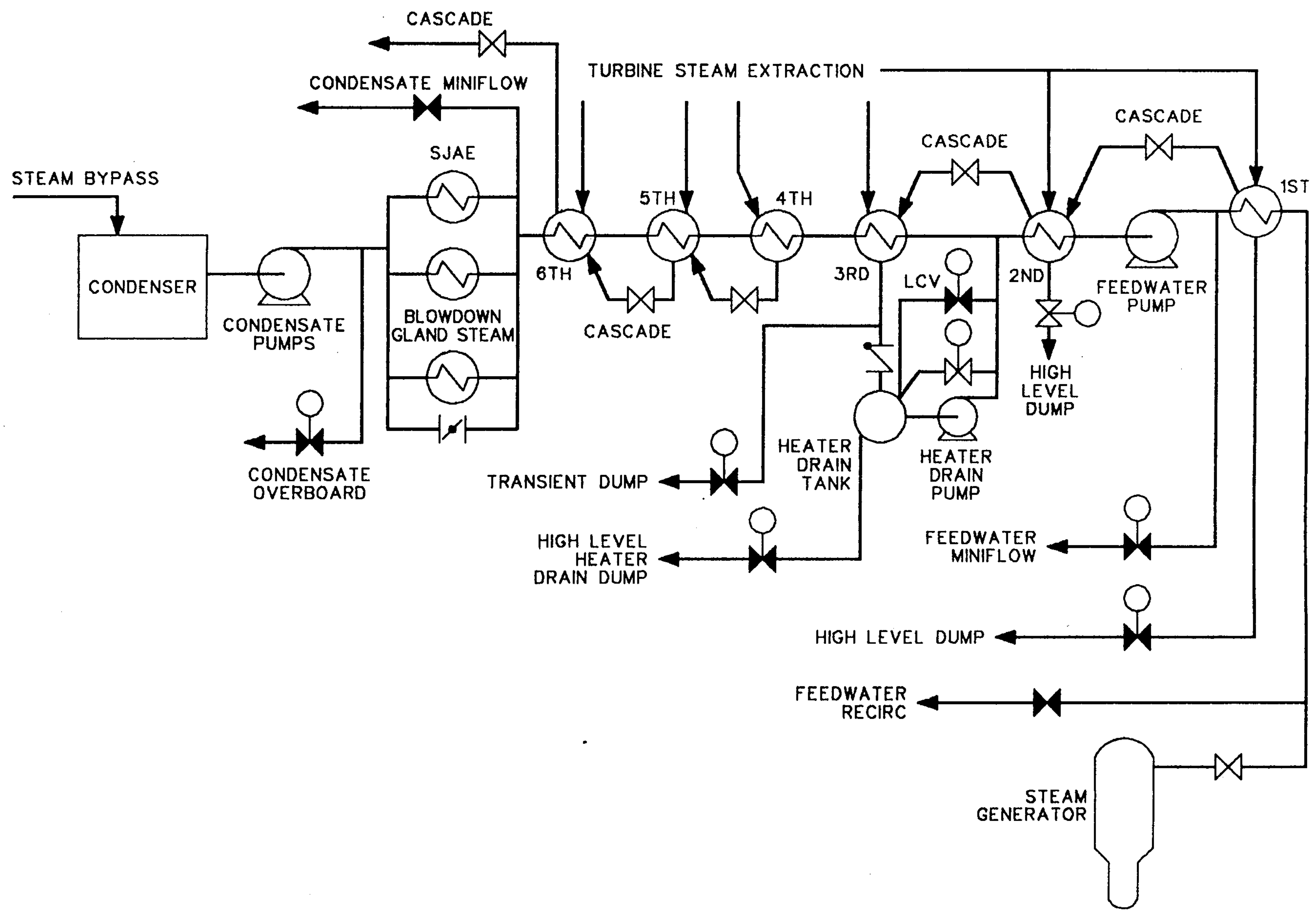


Figure 4-1. Schematic of Feedwater & Condensate System - Normal Operation

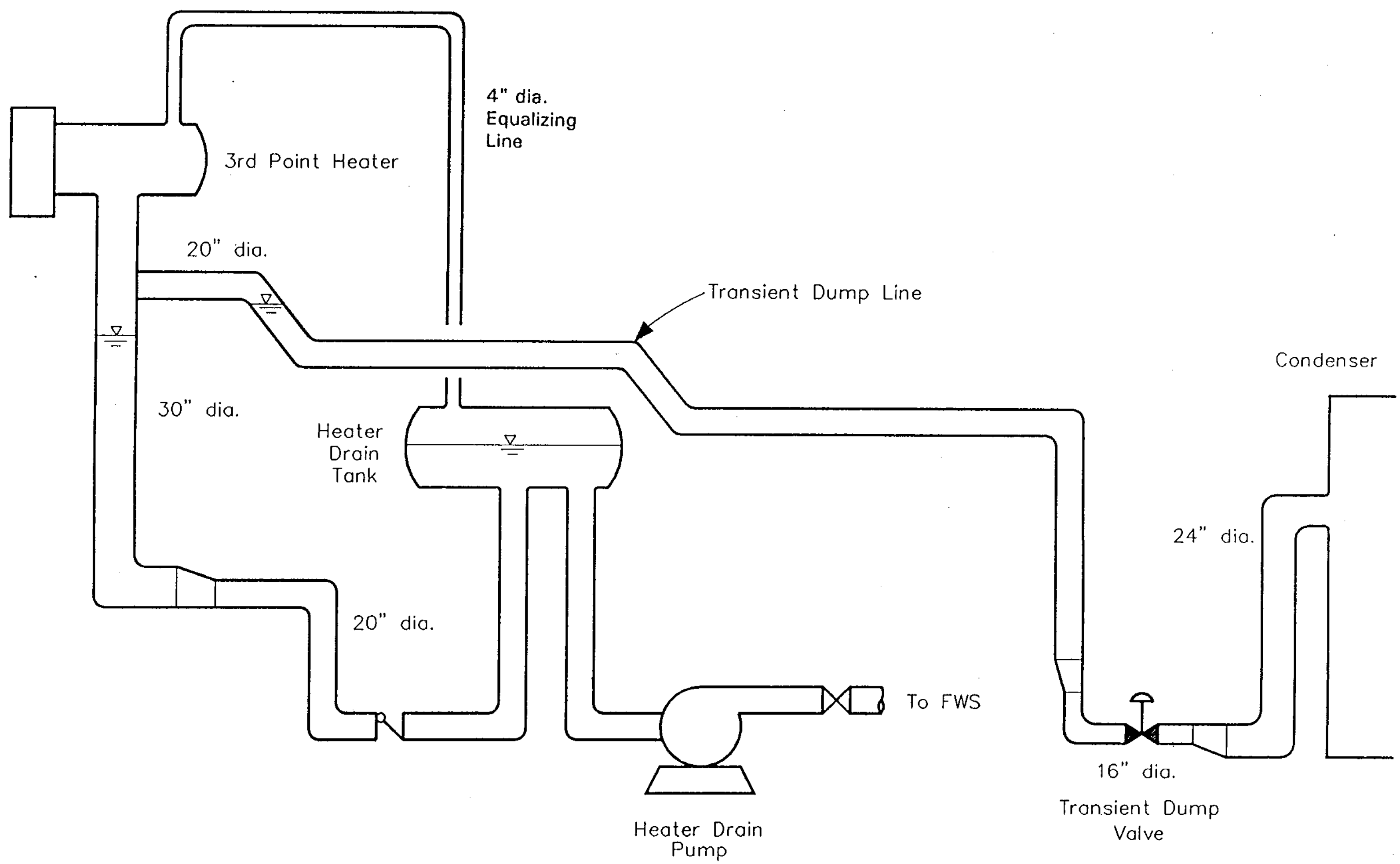
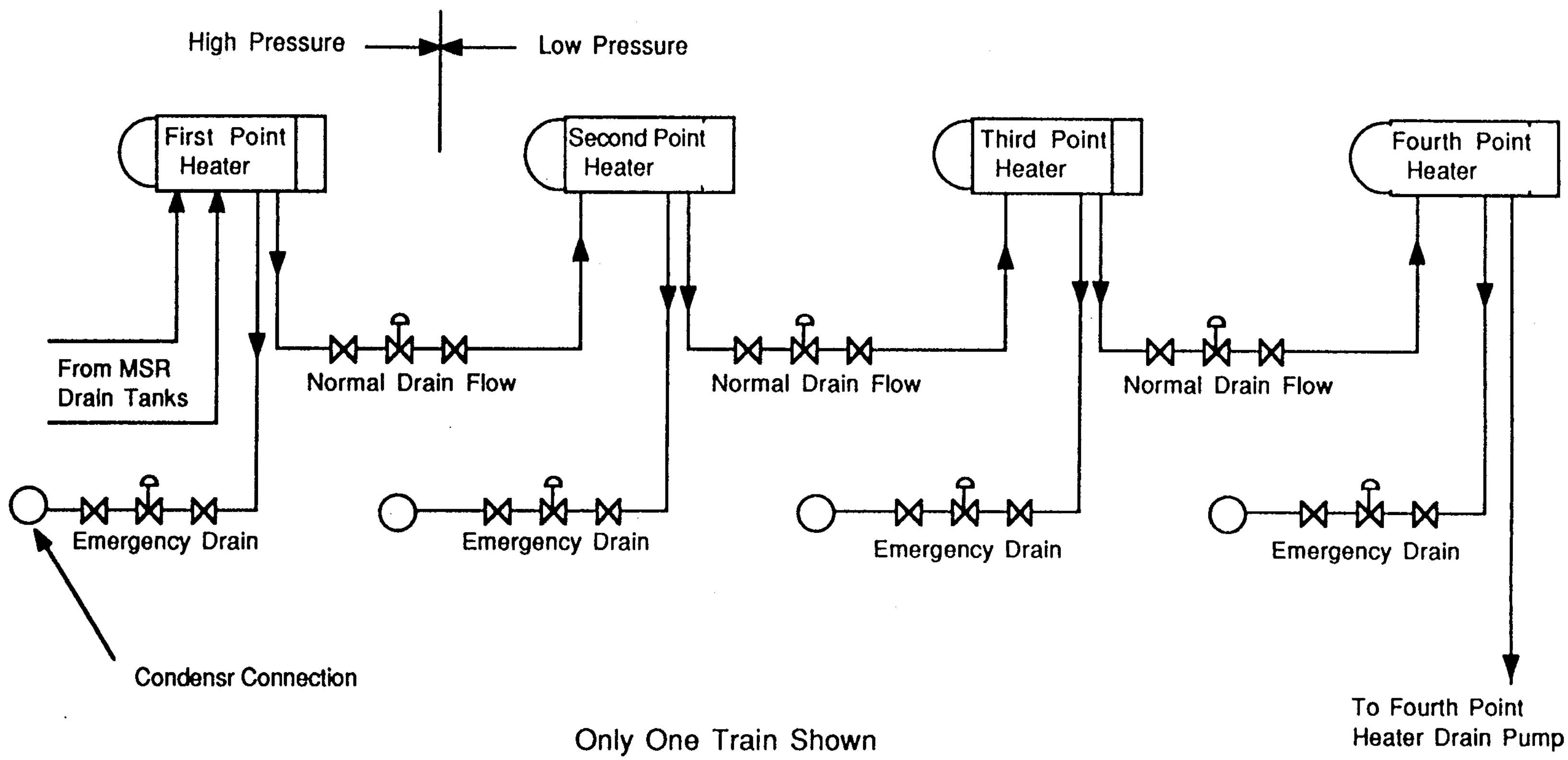


Figure 4-2. Schematic Diagram for Third Point Heater Transient Dump Line



Note: The fifth and sixth point feedwater heaters are condenser neck heaters and are not shown in this flow schematic

Figure 4-3. Feedwater Heater Drains Flow Schematic

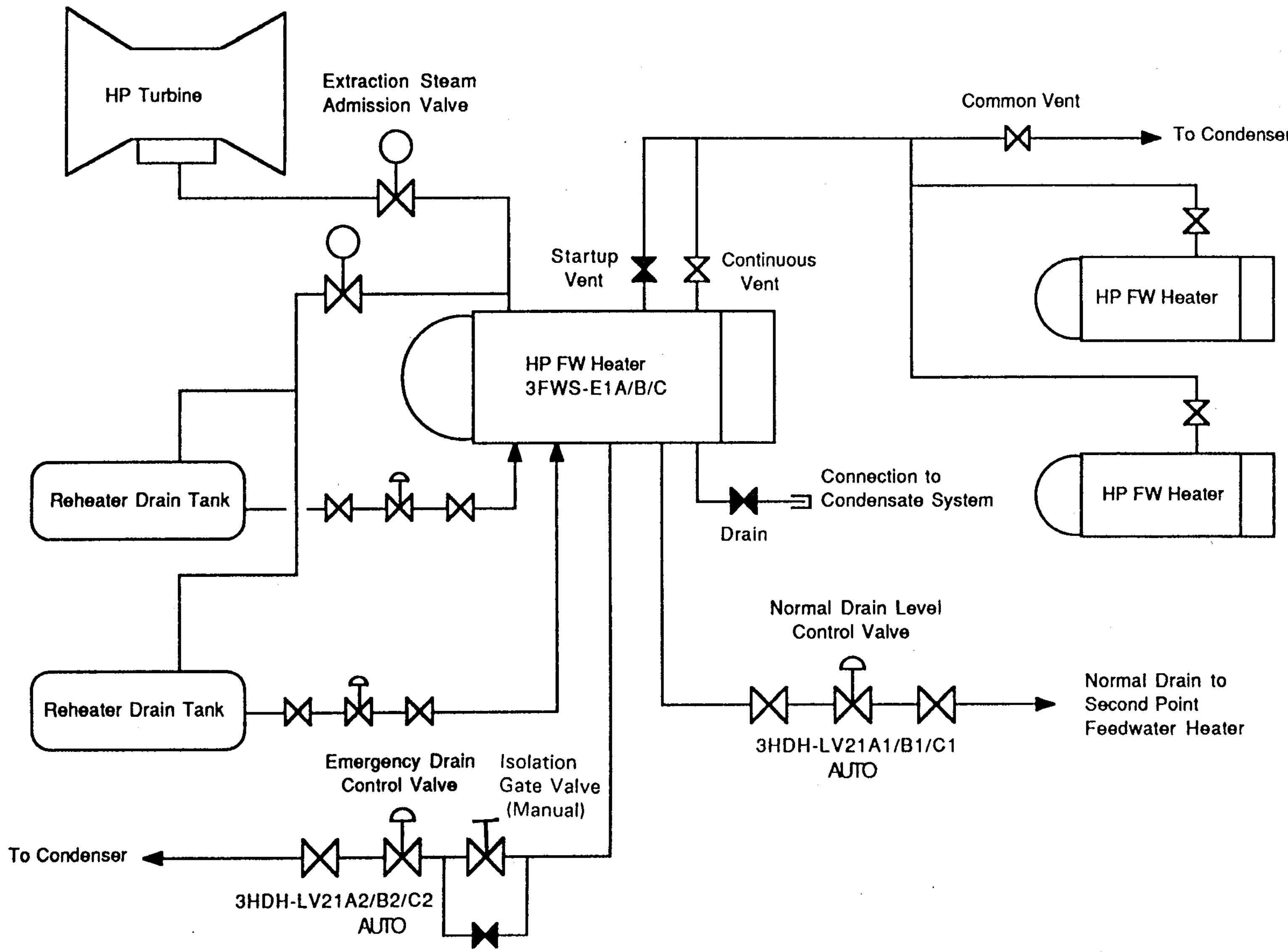


Figure 4-4. High Pressure Feedwater Heater Flow Schematic

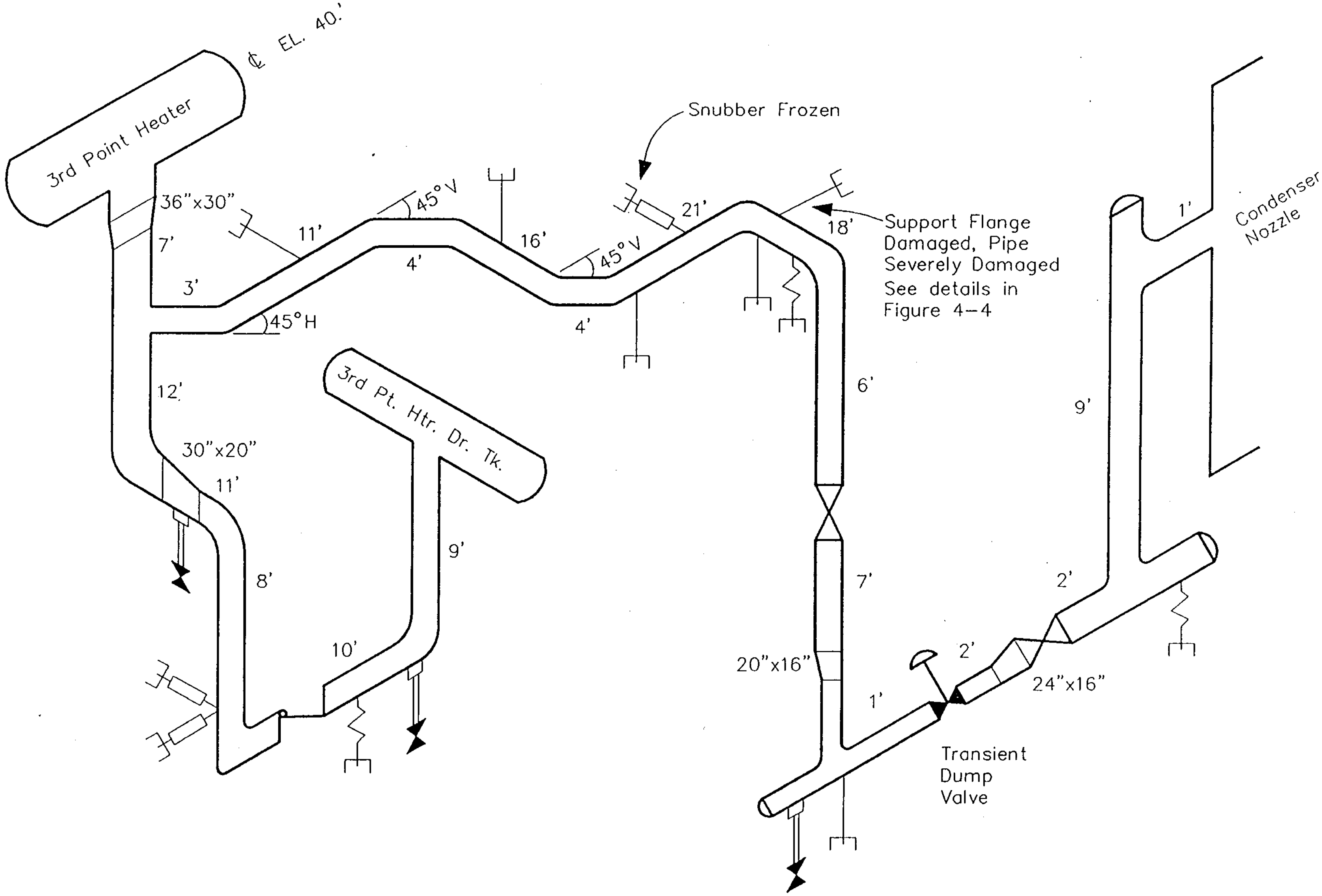


Figure 4-5. Isometric Diagram for Transient Dump Line from 3rd Point Heater to Condenser (Not to Scale)

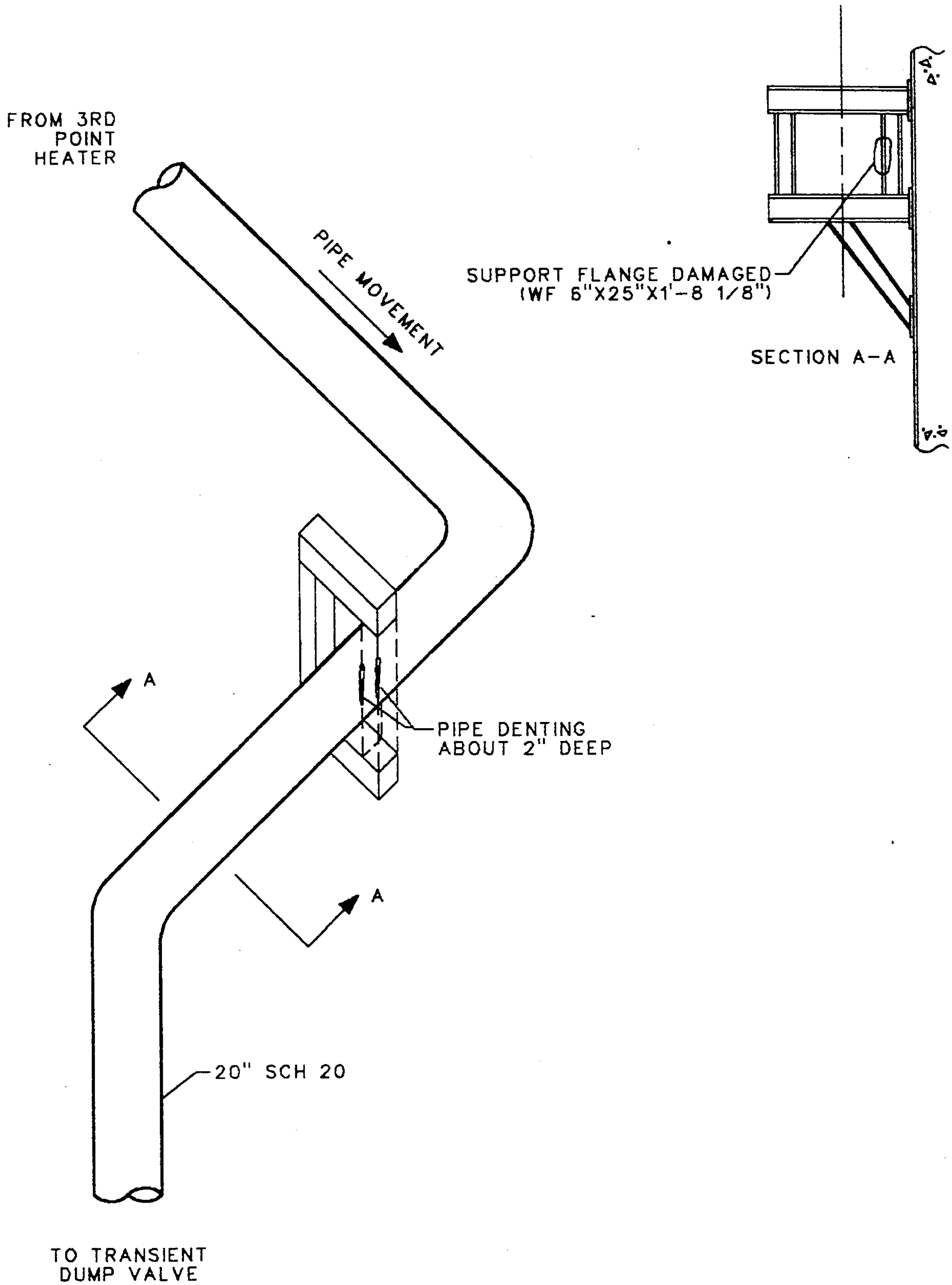


Figure 4-6. Damage Location

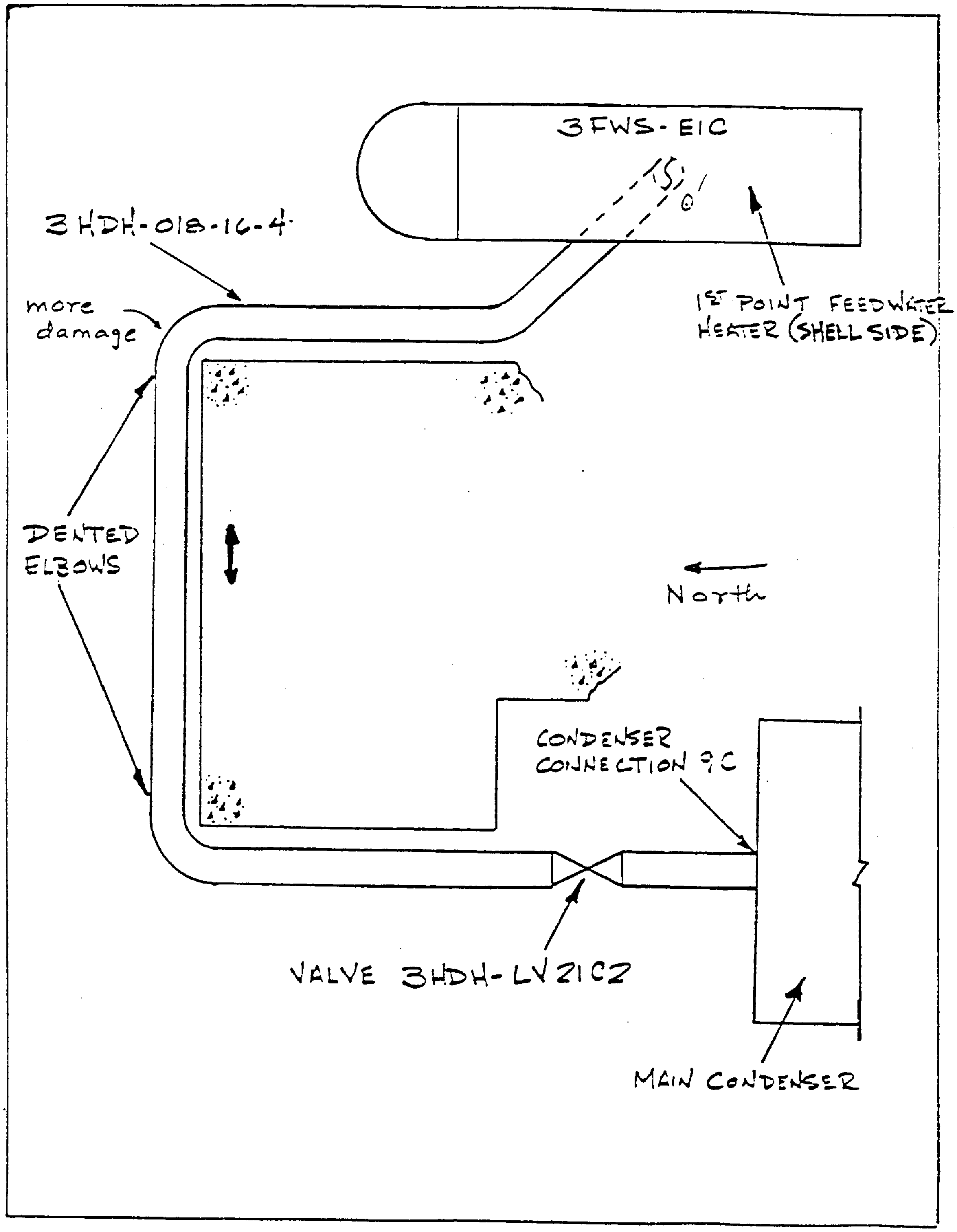


Figure 4-7. Sketch of First Point Heater Drain System

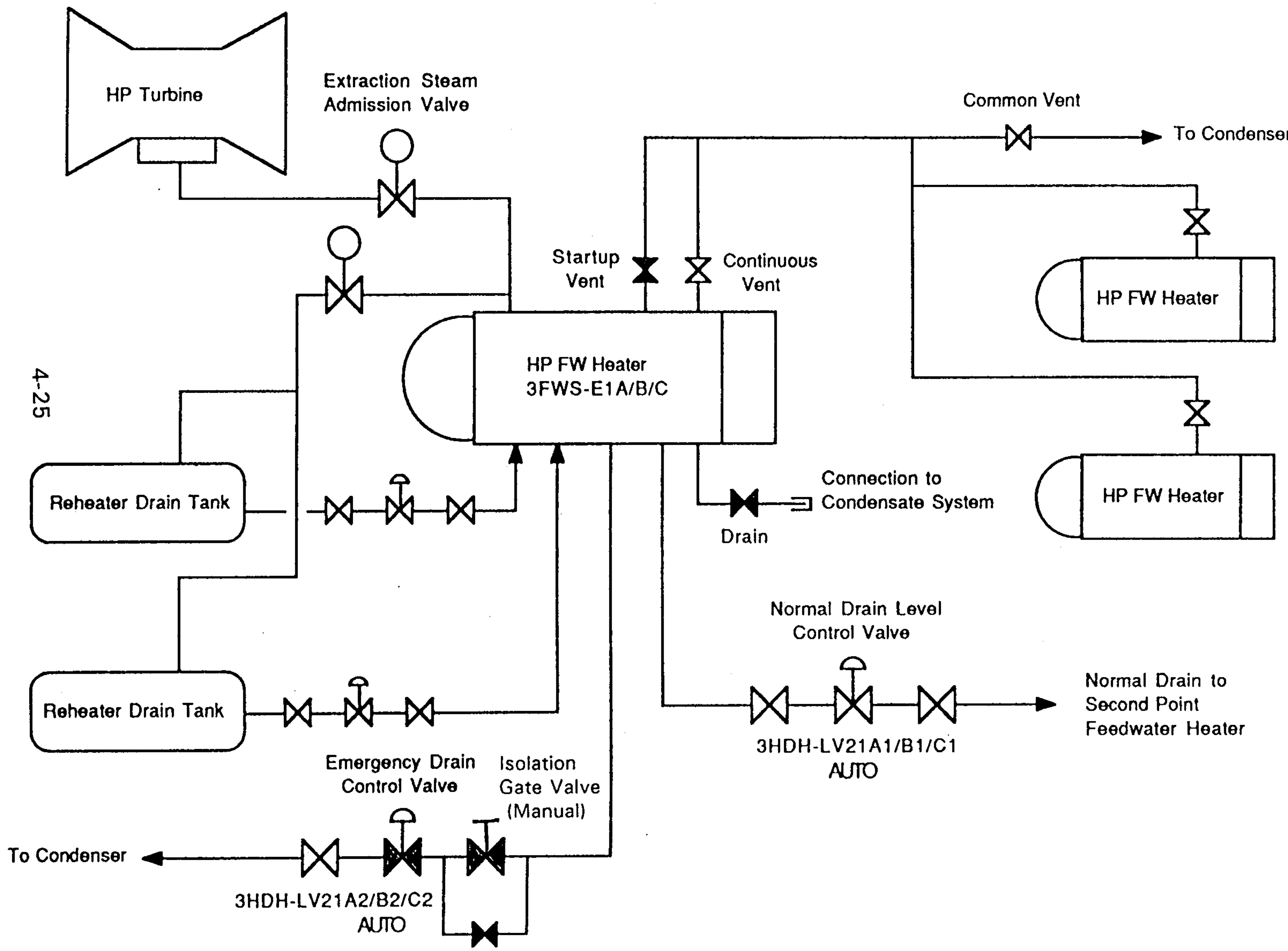


Figure 4-8. High Pressure Feedwater Heater Flow Schematic

4-25

Section 5

STEAM GENERATOR BLOWDOWN SYSTEM IN PWR

SYSTEM FUNCTION

The specific functions of the steam generator blowdown system are to:

- Provide a means of controlling the chemical composition of the steam generator shell water within the specified limits.
- Control solids concentration in the steam generators.
- Transport steam from the steam generator blowdown flash tank to the feedwater heaters.
- Transport liquid from the steam generator blowdown flash tank through a drain cooler to heat feedwater, then purify it by directing it through filters and demineralizers and then return it to the condensate system.

SYSTEM CONFIGURATION, MODE OF OPERATION, AND COMPONENT DATA

System Configuration

A steam generator (SG) blowdown system is shown in Figure 5-1. It consists of steam generators, blowdown flash tank, heat exchanger, filter, and demineralizer bed, with associated piping, valves, and instrumentation. Blowdown from each SG flows through separate lines and blowdown valves to a common flash tank. Steam from the common flash tank flows to the 3rd point feedwater heater, while the liquid is conveyed to the shell side of a drain cooler, before it is purified.

Mode of Operation

This water hammer event described later is suspected to have occurred during re-initiation of SG blowdown flow following system isolation after a reactor trip causing damage to two snubbers. A typical loop for a SG blowdown system is illustrated in Figure 5-2. Containment isolation valve 2FV-4053 closes in about 19 s upon reactor trip, while the blowdown flow control valve 2FV-4056 remains open. This setup allows for a sizeable portion of the 550°F fluid in the 4-in. line between these valves to flash into steam due to the low pressure. The normal operating pressure of the flash tank is 125 psig, but when the isolation valve is closed there exists a scenario where the tank and line could be as low as 5 psig. This is the set pressure of the condenser isolation valve (PCV-3780, Figure 5-1) located at the entrance to the condenser.

The steam generators are normally operating at 1000 psig while passing 300 gpm of either saturated water or a two phase mixture in the line at 550°F. Since the duration of the plant shutdown can last several hours, the fluid in the blowdown line upstream of the closed isolation valve 2FV-4053 (Figure 5-2) has sufficient time to cool-down to a lower temperature, since the majority of this piping is uninsulated. The plant procedures specify that to re-initiate blowdown flow after reactor trip, flow control valve 2FV-4056 should be closed and isolation valve 2FV-4053 should be opened in about 19 s.

The piping immediately downstream of the closed isolation valve was voided and filled with steam as previously discussed. It was also postulated that conditions immediately upstream of the isolation valve consisted of subcooled water at a much higher pressure. This pressure depended on the SG depressurization rate after reactor trip before blowdown was re-initiated, but it could have been as high as 500 psig. Hotter water existed in the pipe near the SG.

Component Data

The major active components in the steam generator blowdown system in a PWR power plant are:

- Containment Isolation Block Valve
- Containment Isolation Block Bypass Valve
- Outside Containment Isolation Valve
- Blowdown Line Check Valve
- Flash Tank Flow Control Valve

Selected data are noted in the Water Hammer Experience subsection for the Steam Generator Blowdown system investigated.

WATER HAMMER EXPERIENCE

In the 1970's a significant number of water hammer events were reported in LWR power plants. This is so, because many power plants were built and began commercial operation in this time period.

Each event was analyzed in the Task 2 Root Cause Report (1) to determine the areas of each system which are prone to water hammer, the specific water hammer mechanism, and root cause. The remedial actions taken by the utility to preclude future occurrence of a similar water hammer were described. Appendices A and B of (1) presented the BWR and PWR utility water hammer databases and Appendix C therein listed the utility plant codes used. Areas prone to water hammer were identified in typical schematics of each system discussed.

It has been determined that a cause of water hammer in steam generator blowdown systems is hot water entering a low pressure line (low pressure discharge).

The procedural and engineering factors contributing to the above occurrence of this type of water hammer are:

- A lack of awareness concerning the possibility of water hammer events, their causes, and potential damages

- A lack of information available to the operator concerning the conditions in the system, to allow for proper action

- Inadequate design considerations for potential water hammer

One event that occurred in the steam generator blowdown system at a PWR power plant is briefly discussed below:

WATER HAMMER EVENT: STEAM GENERATOR BLOWDOWN INITIATION AFTER SYSTEM ISOLATION

Event Description

During refueling inspection, it was discovered that two snubbers (sized PSA-3) on a steam generator blowdown line were damaged as noted on Figure 5-3. Plant personnel reviewed the system configuration and operating procedures and postulated the cause of damage to be the start up of the steam generator blowdown system after a reactor trip. The event occurred shortly after the containment isolation valves on the blowdown system were opened to re-initiate the blowdown operation.

Mechanism Responsible for the Event

When the isolation valve began to open, the initially subcooled water passed through the valve at a high velocity followed by the hotter water which flashed and "choked" when exposed to the low pressure at the valve. This choked flow condition caused an abrupt reduction in the fluid velocity which generated a pressure wave that propagated throughout the piping system causing the snubber damage.

Water Hammer Scenario

After the cause of the reactor trip had been investigated and corrected and the plant was brought back to power, the blowdown system was placed in service again. According to the operating procedure to start the blowdown system, the control valve at the flash tank is first closed, then the containment isolation valve is opened. After the containment isolation valve is fully open, the blowdown flow is slowly increased by opening the flash tank control valve in 10 gpm increments every 5 minutes until normal operating temperature in the blowdown system is achieved.

Prior to opening the containment isolation valve, the blowdown pipe between the steam generator and the isolation valve (length of approximately 256 ft) is filled with stagnant water which has cooled down for several hours. The downstream piping between the containment isolation valve and the control valve at the flash tank (length of approximately 340 ft) is likely at vacuum or partial vacuum. When the containment isolation valve is opened to initiate the blowdown operation, the subcooled water is discharged rapidly into the low pressure piping outside the containment. After the subcooled water flow has cleared the containment isolation valve, the valve capacity will be decreased suddenly due to the "choking" of the hot fluid that follows the cold water through the valve. This generates a pressure wave that propagates throughout the piping system causing damage to the snubbers.

Estimate of Limiting Dynamic Load

It was reported that the damaged snubbers were guaranteed to operate up to a load of 11,700 lbs (see Table 2.1 - Assessment Guidelines) (2). Furthermore, the vendor's post-event test results indicated that the force required to damage the trunnion was approximately 22,000 lbs.

The peak load that a low pressure discharge water hammer could generate is obtained as described in Section 6 of the Water Hammer Assessment Guidelines (2). The SG is assumed to be at 400 psia and 440°F which is a lower bound estimate depending on the SG depressurization rate after reactor trip before blowdown re-initiation. From Table 6-6 (Assessment Guidelines), obtain P_v = 3793 psi. P_v is the pressure rise at the valve due to a change in fluid velocity (mass flux) that occurs when discharging subcooled water followed by hot water.

Assuming the valve opening was 30 percent of the pipe flow area at the time that the hot water reached the valve, this reduces the peak pressure in the pipe to 1138 psi (3793 x 0.3). Since the pipe flow area is approximately 28.3 in^2, the peak pipe segment force could be 1138 x 28.3 = 32,200 lbs in the piping upstream of the isolation valve. This force exceeds the trunnion damage force of 22,000 lbs.

Corrective Measures

The utility resolved this water hammer by slowly refilling the system after a reactor trip and prior to opening the isolation valve. With the current system configuration, this may be done by slowly injecting water into the voided piping downstream of the isolation valve. Another more effective method to restrict the refill rate of the voided blowdown piping is to install a small bypass valve around the containment isolation valve located outside the containment to gradually fill the voided piping prior to initiating the blowdown flow.

Other Postulated Water Hammer Root Causes

Based on the above-described scenario and evidence, the root cause leading to this event is the pressure rise caused by a reduction in mass flux when a valve is discharging subcooled water followed by hot water that "chokes."

Void formation and collapse in piping both upstream and/or downstream of the isolation valve have also been postulated as root causes of a water hammer in this system as described below.

Void formation in upstream piping is postulated by assuming that modest depressurization waves propagate upstream towards the SG when the isolation valve is opened causing some hot fluid to flash. Additionally, the rapid acceleration of the subcooled water through the valve could also cause flashing due to a reduced pressure in the piping caused by fluid friction losses. The is not the most likely scenario since (1) the formation of a large void would be in competition with the high SG pressure attempting to prevent its formation and (2) the pressure rise caused by the collapse of a steam void is much greater than that previously determined due to the Mechanism 4 water hammer since a relatively high closure velocity would exist for steam bubble collapse. This in turn would likely have caused more piping or support damage.

The utility postulated that steam void formation in downstream piping is likely since the flow control valve is left open allowing the piping to drain and/or the hot fluid to flash due to the reduced pressure. A water hammer could occur when the blowdown is re-initiated when the subcooled water passing through the newly opened isolation valve impacts against the closed flow control valve downstream causing a Mechanism 3 water hammer. This is not the most likely scenario since: (1) there was no reported piping or support damage in the piping system near the closed valve; the damaged snubbers were upstream of the newly opened isolation valve, and (2) a water hammer pressure wave could not propagate from the closed flow control valve back toward and then through the isolation valve if the flow through the isolation valve were choked. Nevertheless, the postulated Mechanism 3 type water hammer should also be avoided.

SYSTEM EVALUATION

Normal Transients

There are no expected transients that steam generator blowdown systems are typically designed for such as pump start-up or rapid valve actuation. However, the system design does consider temperature and pressure conditions for all flows to minimize undesired flashing.

Severe Transients

Hot saturated water entering a low pressure line is the most common cause of water hammer in this system. This piping system is not normally designed to withstand this type of water hammer.

REVIEW OF OPERATING, TESTING, AND MAINTENANCE PROCEDURES

Operating Procedures

The normal operating procedure for re-initiation of the SG blowdown system after reactor trip is to (see Figures 5-1 and 5-2):

- Close flow control valve 2FV-4055 (2FV-4056) (located at flash tank).
- Open blowdown containment isolation valve HV-4054 (HV-4053).
- Open valve to discharge to sea line.
- Slowly increase blowdown flow rates at the flow control valve in 10 gpm increments every five minutes until normal operating procedures are met.

The utility revised these procedures after investigation of the water hammer event as follows:

- Close flow control valve 2FV-4055 (2FV-4056) (located at flash tank).
- Enter the containment and close block valve 6"-015-C-129.
- Open blowdown containment isolation valve HV-4054 (HV-4053).
- Open the 3/4-in. diameter equalizing valve around the closed 6-in. diameter block valve.

- When the downstream line is pressurized, open the closed block valve.
- Close the 3/4-in. bypass valve.
- Open valve to discharge to sea line.
- Slowly increase blowdown flow rates at the flow control valve in 10 gpm increments every five minutes until normal operating procedures are met.

The water hammer event was mitigated by the previously described revision to the operating procedures.

An additional revision to the operating procedures might include a requirement to close both the isolation and flow control valve (previously left open) after reactor trip to prevent drainage of the piping downstream of the isolation valve. In addition, any voids that may form due to flashing at low pressure in the piping downstream of the closed isolation valve could be pressurized by the installation and use of another small bore (3/4 in.) bypass line around the closed isolation valve.

Testing Procedures

This water hammer does not occur during normal operating procedures, and only arise after reactor trip upon re-initiation of the SG blowdown system. Therefore, testing of this system for this mode of operation is not a normal occurrence.

Maintenance Procedures

There were no maintenance or inspection procedures observed for this event, for the same reason as described in testing procedures above. If level indicators and temperatures elements were present to detect line voids or cold/hot water interfaces, regular inspection procedures for this system would provide plant personnel with enough information to identify if conditions are right for a potential water hammer occurrence.

In addition, insulating the pipe to prevent substantial cooldown of the normally hot water after reactor trip is a recommended maintenance procedure.

STRENGTHS AND WEAKNESSES FOR WATER HAMMER PREVENTION

Strengths

The recommended change to the operating procedure of using the bypass valve around the block valve to pressurize the system prior to opening the isolation valve seems to have mitigated the water hammer event. However, several concerns still exist as to whether all water hammers have been mitigated on this system as described below.

Weaknesses

Normal operation of the SG blowdown system after reactor trip has the following weaknesses even after the recommended change to the operating procedures:

- The procedures do not allow for filling of the piping downstream of the closed isolation valve after reactor trip, which is most likely almost totally voided since the flow control valve remains open. Re-initiation of blowdown could cause a Mechanism 3 water hammer.

- The normally hot water that may not drain in this downstream piping will probably flash due to the reduced pressure in the line. Water slugs could also form over time in the 3 ft horizontal run and 15 ft riser located downstream of the closed isolation valve (see Figure 5-3) leading to a Mechanism 5 type water hammer.

- Hot water near the SG and subcooled water near the isolation valve could still exist in the piping after cooldown upstream of the closed isolation valve, since a portion of the piping is uninsulated. This could cause a Mechanism 4 type water hammer upon opening of the closed isolation valve.

REFERENCES

1. Van Duyne, D. A., Yow, W., and Sabin, J. W., "Water Hammer Prevention, Mitigation, and Accommodation, Task 2 - Root Cause Analysis for Plant Water Hammer Experience," EPRI RP-2856-3, Task 2 Report, December 1989.

2. Van Duyne, D. A., Sabin, J. W., and Rooney, J. W., "Water Hammer Prevention, Mitigation, and Accommodation, Task 5 - Water Hammer Assessment, Prevention, and Diagnostic Guidelines," EPRI RP-2856-3, Task 5 Report, October 1990 draft report.

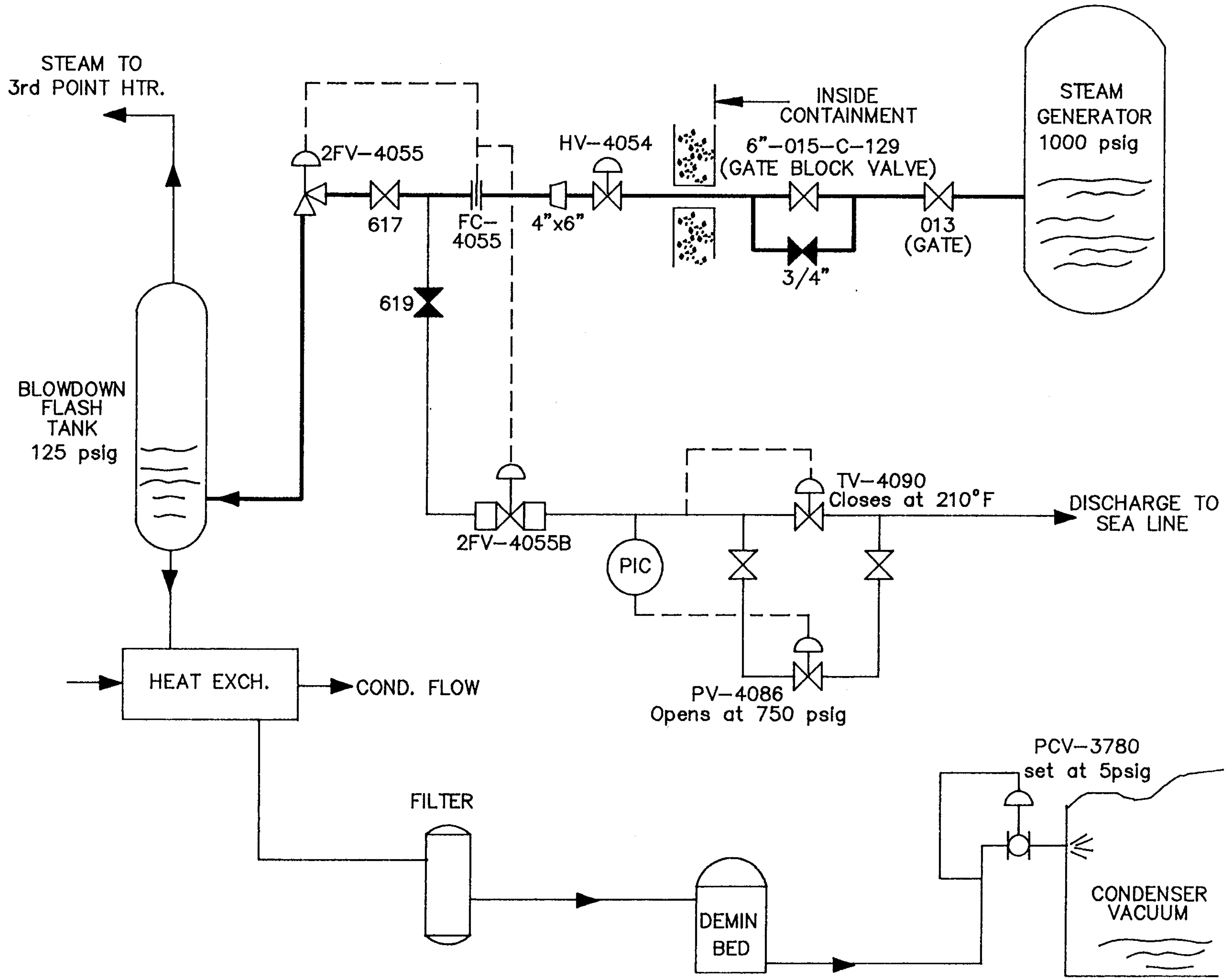


Figure 5-1. Typical Steam Generator Blowdown System

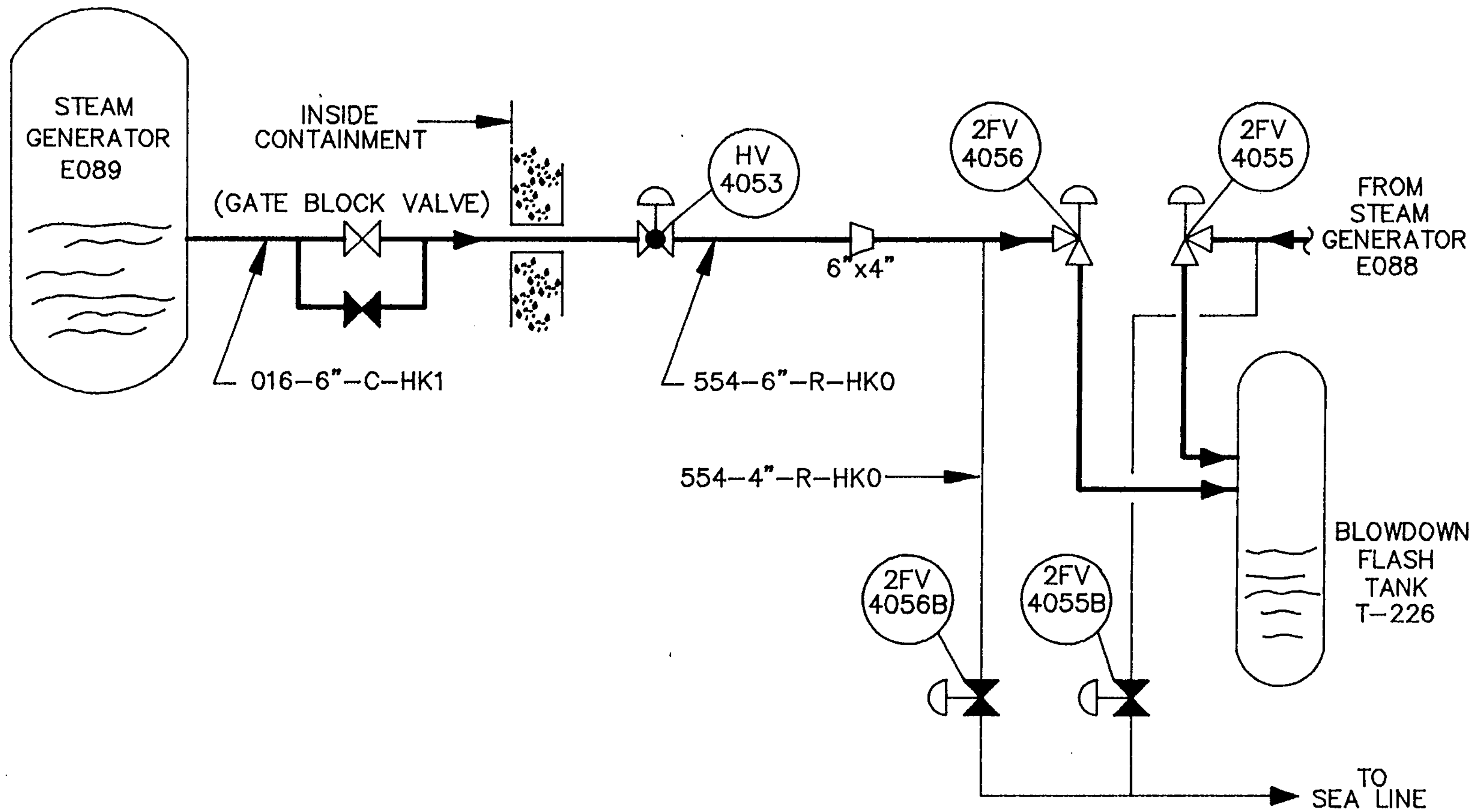


Figure 5-2. Typical Loop for Steam Generator Blowdown System

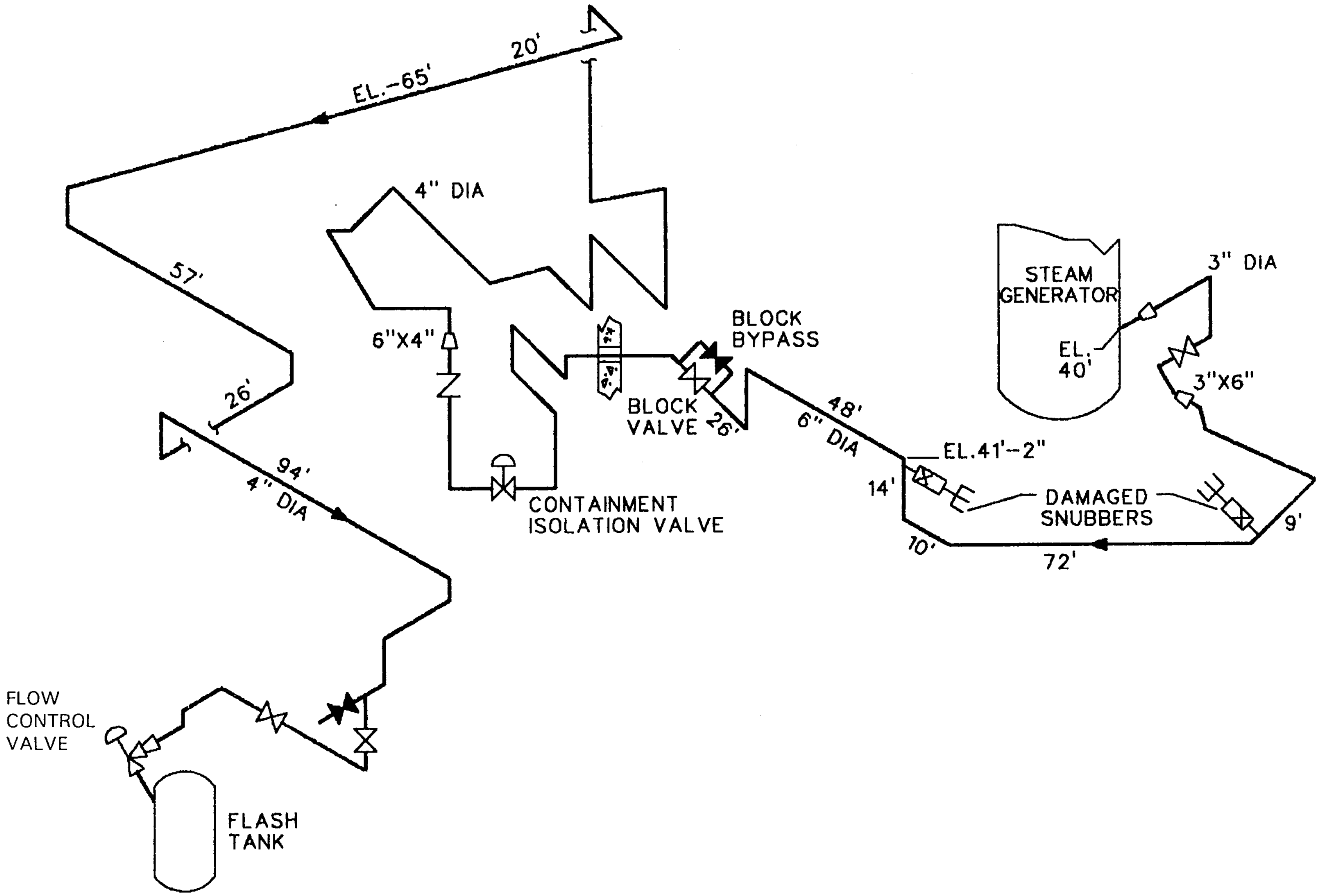


Figure 5-3. Isometric Drawing for Steam Generator Blowdown System

Section 6

AUXILIARY FEEDWATER TURBINE STEAM SUPPLY SYSTEM IN PWR

SYSTEM FUNCTION

The auxiliary feedwater turbine steam supply system routes steam from the steam generators to the auxiliary feedwater turbine to power the turbine driven pump. The turbine has a single supply line which is served by two steam generators. The turbine can be sufficiently supplied with either steam generator isolated. The steam supply line is QA category I and acts to keep the auxiliary feedwater system operable for certain transients including a loss of electrical power.

SYSTEM CONFIGURATION, MODE OF OPERATION, AND COMPONENT DATA

System Configuration

The steam supply line for the auxiliary feedwater (AF) turbine branches from the main steam headers of two steam generators. A motor operated valve in the main steam supply line isolates the line in the event of a steam line break downstream. Control valves admit steam to the auxiliary feedwater turbine. Drain traps are provided at system low points and upstream of turbine stop valves to prevent the collection of condensation.

Mode of Operation

This water hammer event occurred during system testing of the turbine-driven feed pump or after automatic initiation of the auxiliary feedwater system.

It was believed that excessive condensate accumulated in the steam supply line because of solenoid drain valve failure resulting in incomplete draining during system heatup before the auxiliary feed pump turbine startup.

Component Data

The major active components in the AF steam supply system in a PWR plant are:

- Steam Supply Valves
- Solenoid Drain Valves
- Steam Traps
- Supply Line Tilting Disc Check Valves
- Turbine Driven Auxiliary Feedwater Pump
- Turbine Stop Valve
- Turbine Governor Valve

WATER HAMMER EXPERIENCE

In the 1970's a significant number of water hammer events were reported in LWR power plants. This is so, because many power plants were built and began commercial operation in this time period.

Each event was analyzed in the Task 2 Root Cause Report (1) to determine the areas of each system which are prone to water hammer, the specific water hammer mechanism, and root cause. The remedial actions taken by the utility to preclude future occurrence of a similar water hammer were described. Appendices A and B of (1) presented the BWR and PWR utility water hammer databases and Appendix C therein listed the utility plant codes used. Areas prone to water hammer were identified in typical schematics of each system discussed.

It has been determined that a cause of water hammer in auxiliary feedwater turbine steam supply systems is steam propelled water slug.

The procedural and engineering factors contributing to the above occurrence of this type of water hammer are:

- A lack of awareness concerning the possibility of water hammer events, their causes, and potential damages;

- A lack of information available to the operator concerning the conditions in the system, to allow for proper action;

- Inadequate design considerations for potential water hammer

One event that occurred in the AF steam supply line at a PWR power plant is briefly discussed below:

WATER HAMMER EVENT: TURBINE-DRIVEN AUXILIARY FEEDWATER PUMP START

Event Description

During the refueling outage inspection, it was found that the tilting disc check valves located in the individual steam supply lines from the steam generators and two snubbers located in the common steam supply header to the turbine were damaged (see Figure 6-1). Inspection of the failed check valves revealed that both hinge pins of the tilting disc check valves were bent from the pin centerline. The disc bushings were also cracked.

Mechanisms Responsible for the Event

It was suspected that water slugs were formed in the turbine-driven auxiliary feedwater pump steam supply lines as a result of two condensate drain solenoid valves failure to open and provide adequate drainage. When the feedwater pump turbine throttle valve was opened for the operational test, the steam behind the condensate accelerated the water slug through the piping system. This resulted in the water slug impacting system components causing damage (see Figure 6-2).

Slug Formation

Plant personnel suspected that the water hammer event was caused by slug flow in the steam line and inspected the system low point drains. The inspection revealed that two low point drain solenoid valves at the steam supply lines for both steam generators had become stuck in the closed position, allowing condensate to collect in the 4-in. diameter piping. The piping geometry is such that a slug of up to 14 ft long could have collected. When the turbine throttle valves were opened for the test, the water slug was accelerated into the piping system causing damage to the check valves upon impact and damage to the snubbers as they restrained the pipe as the slug passed by.

Estimate of Slug Impact Load

Based on the deformed configuration of the hinge pins and the yield stress of the hinge pin material, the post-event analysis conducted by the check valve manufacturer resulted in an estimate of about 4,500 ft-lb of total energy absorbed by the hinge pins. The energy absorbed by the deformed hinge pins can be related to the kinetic energy of the water slug as follows:

$$0.5(\rho\, L_s\, A)V_s^2 = 4{,}500 \text{ ft-lb} \qquad (6\text{-}1)$$

where ρ is the density of water in slug/ft^3, L_s and A are the water slug length and the cross-sectional area of the pipe, and V_s is the water slug velocity prior to impacting the valve disc. By using the water density of 62.4 lb/ft^3 (1.94 slug/ft^3), the cross-sectional area of the pipe of 0.087 ft^2, and the length of the water slug of approximately 14 ft (which is based on the pipe length in the section of low elevation of the steam supply line where the water slug is most likely to accumulate), the water slug velocity prior to the impact is calculated to be about 62 fps.

When the water slug had accumulated and filled up a segment of the steam supply pipe, the water would be accelerated by the differential pressure across it when the turbine throttle valves were opened. The acceleration would be countered by the friction between the slug and the pipe wall, especially if the slug would travel a significant distance in a small size pipe. Taking into consideration this frictional effect, the maximum or terminal slug velocity (V_o) can be determined by the following equation from Section 7 in Task 5 Assessment Guidelines (2):

$$\Delta P_f = \frac{\rho f L_s V_o^2}{2D} \qquad (6\text{-}2)$$

where ΔP_f is the differential pressure in lb/ft^2 across the slug, ρ the mass density in $slugs/ft^3$, f is the Darcy-Weisbach friction coefficient, L_s the slug length in ft, and D is the pipe diameter in ft. It was reported that for this event, the differential pressure is estimated to be about 25 psi, which is the steam generator pressure (saturated steam at about 240°F) on the upstream side of the slug, and condenser pressure (about full vacuum) on the downstream side. D is 0.33 ft, L_s is about 14 ft, and f is estimated to be approximately 0.022. Based on the 25 psi differential pressure across the water slug, the maximum slug velocity is calculated from the above equation to be 63 fps. This velocity correlates very well with that required for the kinetic energy absorbed by the deformed hinge pins discussed previously.

Fenton (3), (4) performed experimental tests of clearing trapped water in piping. In his apparatus the limited air flow resulted in pressure buildup of approximately 20 psig upstream of the clearing slug, similar to the differential pressure of 25 psi in the AF steam lines being evaluated.

Forces were measured by Fenton (4), as presented in Figure 6-3. These data are plotted versus the dispersion distance D^* defined by:

$$D^* = \frac{L\ A}{V_{vol}} \qquad (6\text{-}3)$$

The volume of the trapped water is V_{vol} and A is the pipe area, so V_{vol}/A is the mean length of pipe filled by the water. Since L is the distance from the upstream end of the liquid slug to the pipe bend in Figure 6-4, L divided by D^* is the number of times that the slug travels its own length before passing the bend.

It is shown in the Assessment Guidelines (2) that the slug forces reduce significantly after the slug has traveled approximately 8 times its length. However, the original slug length of 14 ft could have been longer and could have mixed with steam to form a much longer slug with reduced density, thus making impact on the partially opened check valve likely.

Water Hammer Root Causes

The root cause of this water hammer event is lack of adequate draining capability due to both design and procedural concerns which allow the accumulation of a water slug in the steam supply line prior to initiating the steam flow. The accumulated water slug is caused by the two stuck closed low point drain solenoid valves downstream of the steam supply isolation valves.

Water Hammer Concerns Identified During Walkdown

A walkdown of the auxiliary feedwater steam supply system was performed to identify other system configurations which might lead to a reduction in system reliability due to the collection of condensate in the steam supply lines. This system configuration is shown in Figure 6-1.

Two potential concerns were identified during the walkdown. The first one is a procedural concern in that the steam generator used to keep the steam supply line warm was steam generator No. 2, while the steam supply from steam generator No. 1 was closed. Since the steam supply line from steam generator No. 1 (about 200 ft) is considerably longer than that from steam generator No. 2 (about 20 ft), this isolated about 200 ft of steam piping downstream of the steam supply valve from steam generator No. 1, which was not heated by the incoming steam from steam generator No. 2. This allowed the formation of condensate upstream of the check valve due to steam leaking past the valve seat to a lower pressure area (possibly condenser vacuum). The same phenomenon could also occur if steam generator No. 1 were used instead to heat the turbine steam supply line; however, the run of unheated piping would be much shorter in this instance, and the possibility for slug formation is much less.

The second concern noted was the existence of an undesirable low point in the steam supply line from steam generator No. 1 (see Figure 6-5). This loop would allow the collection of condensate in the piping which could not be removed by the existing low point drains and, therefore, represents the potential for slug flow in the system even if the drains are functioning properly.

Corrective Measures

The utility replaced the failed solenoid drain valves with steam traps and implemented a surveillance program to ensure that the steam supply lines remained free of condensate. Plant operators later noted that the steam traps were ineffective in removing the condensed steam, and these traps were subsequently replaced with constant flow orifices. Since these drain orifices were installed, the steam supply lines have remained free of collected condensate. However, installation of the orifices resulted in small pressure fluctuations within the steam supply lines which caused the check valves to chatter. This valve chattering problem was eliminated by using steam from only one steam generator to keep the turbine steam supply line warm, while the other steam supply valve was kept shut and only opened on a signal to provide auxiliary feedwater flow.

However, to ensure that the auxiliary feedwater turbine steam supply piping is warmed up properly prior to automatic startup, it is preferred that the steam supply isolation valves on both lines be opened. This can best be accomplished by relocating the existing check valves to immediately downstream of the respective steam supply valves. An alternative to this will require the constant drain orifices to be sized to mitigate the pressure fluctuation causing the check valve to chatter, if possible. If the configuration is such that a reasonable orifice size will not prevent the check valve from chattering, then a smaller check valve bypassing the turbine steam supply check could be installed. Furthermore, if only one steam supply line is used for heat-up, the preferred choice would be the one with longer steam supply piping. So, keeping the steam supply isolation valve from steam generator No. 1 open with the installation of system low point drains just upstream of both check valves would mitigate slug formation.

SYSTEM EVALUATION

Normal Transients

There are no expected water hammer transients that AF steam supply systems are typically designed for such as pump start-up or rapid valve actuation. Most systems are designed with drain valves which are assumed to function as designed.

Severe Transients

The most likely water hammer transient is a steam propelled water slug. This piping system is not normally designed to withstand this type of water hammer, because the postulated water slug formation is based on an active failure of a drain valve.

REVIEW OF OPERATING, TESTING, AND MAINTENANCE PROCEDURES

Operating Procedures

One operating procedure that was previously discussed is concerned with the fact that the steam generator used to keep the steam supply line warm was steam generator (SG) No. 2, while the steam supply from SG No. 1 was isolated. Since the steam supply line from SG No. 1 (about 200 ft) is considerably longer than that from SG No. 2 (about 20 ft), a significant amount of steam supply piping is not sufficiently warmed up (see Figure 6-1). This allows for the formation of condensate upstream of the check valve in the isolated line due to steam leaking past the valve seat to a lower pressure area (possibly condenser vacuum). The same phenomenon could also occur if SG No. 1 were used instead to heat the turbine steam supply line; however, the run of unheated piping would be much shorter in this instance, and the possibility for slug formation is much less.

Testing Procedures

The steam supply line is normally tested once a month, coinciding with the AF turbine testing frequency. Prior to the turbine testing, it should be ensured that the system low point drains (orifices) are operating properly and condensate has not collected in the piping system.

An additional testing procedure may include a requirement to slowly warm up and repressurize an isolated steam line before operation, hence mitigating the formation of a water slug and the differential pressure that may exist across it.

Maintenance Procedures

The utility instituted a surveillance program to ensure that the steam supply lines remained free of condensate. This surveillance program revealed that the newly installed drain valves (that were not functioning the first time), still were not functioning properly. Constant flow orifices were subsequently installed and condensate collection problems were mitigated.

It was noted that during one walkdown, a low point exists in the piping system where condensate could collect. The current drain configuration could not remove this condensate.

STRENGTHS AND WEAKNESSES FOR WATER HAMMER PREVENTION

Strengths

Some utility-implemented strengths were observed during investigation of this water hammer event. One was the installation of constant flow drain orifices to mitigate condensate collection and subsequent removal problems. In addition, a surveillance program was instituted to regularly monitor the piping system for slug formation.

Weaknesses

Several weaknesses still exist on this system as follows:

- Low points exist in the piping system without proper drainage.
- Only one steam supply line is kept warm during operation.

- The system configuration does not allow for slow warmup of steam lines.
- The reliability of the steam supply line low point drain solenoid valves is questionable (unless replaced with constant flow orifices).

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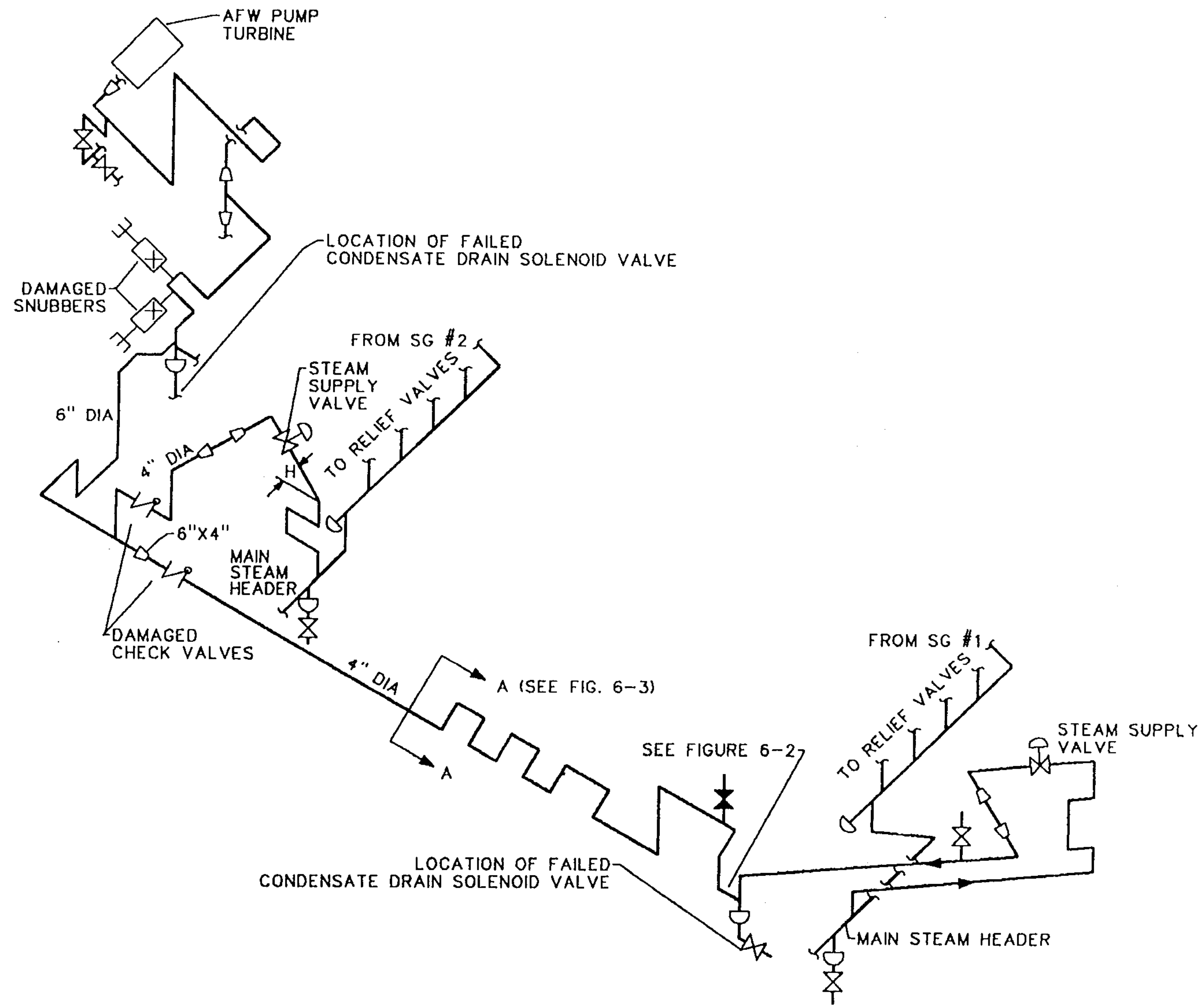


Figure 6-1. Auxiliary Feedwater Pump Turbine Steam Supply

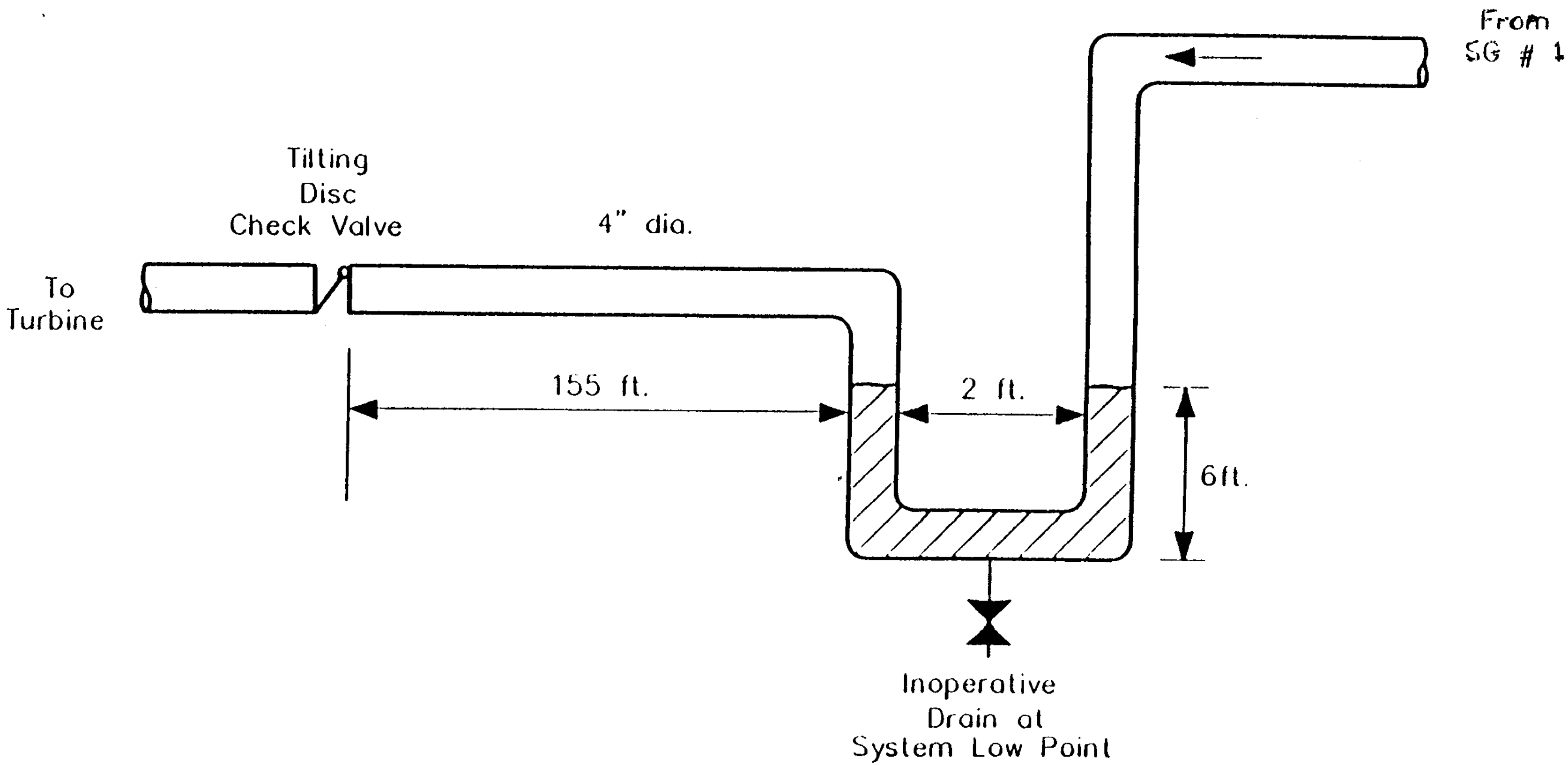
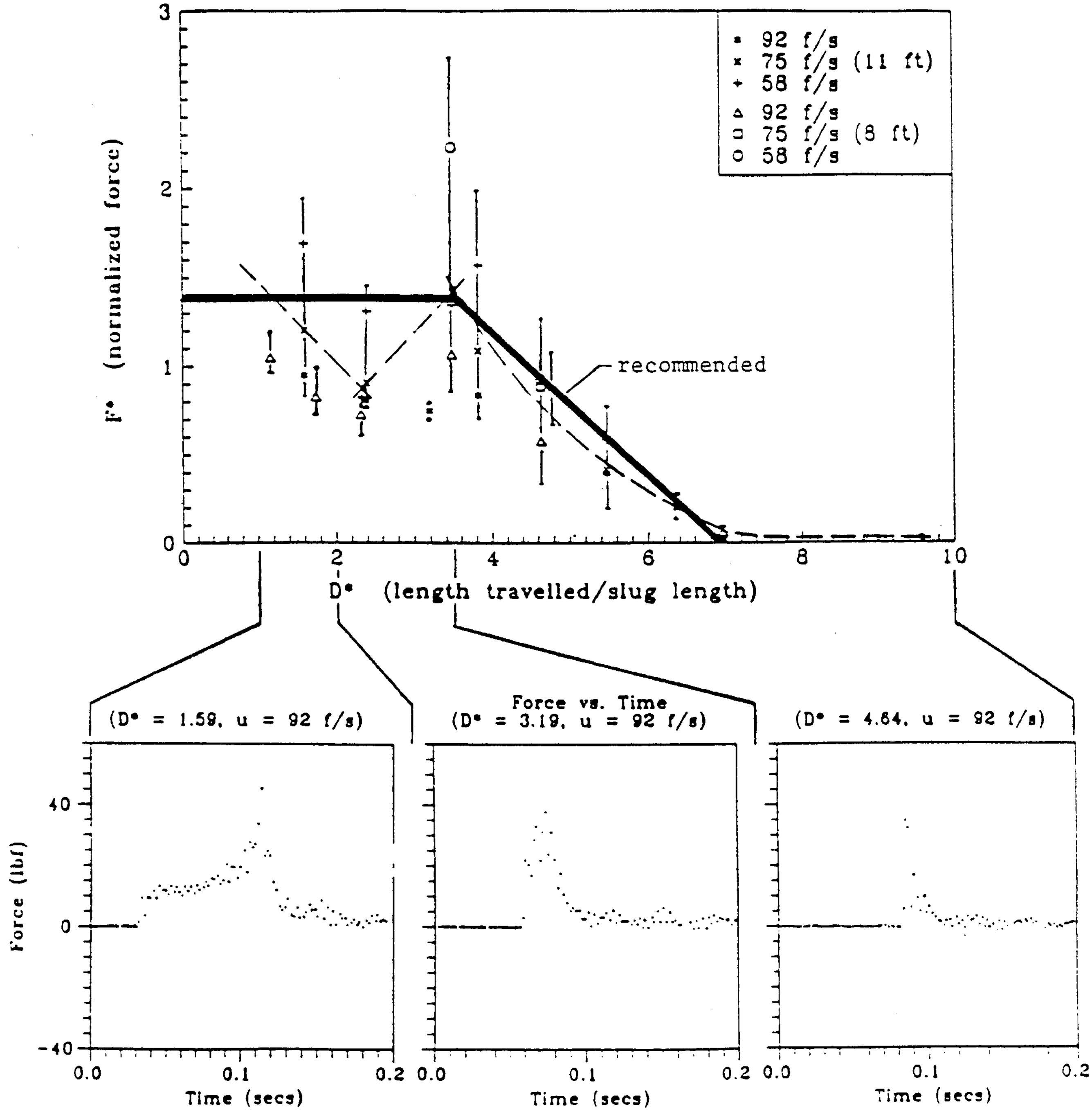


Figure 6-2. Schematic for Development of Water Slug in Steam Supply Line



NOTE: THE FORCE REGIMES ILLUSTRATED BELOW. FORCE IS NORMALIZED TO NOMINAL GAS VELOCITY.

Figure 6-3. Normalized Force vs. Dispersion Distance Reference (4)

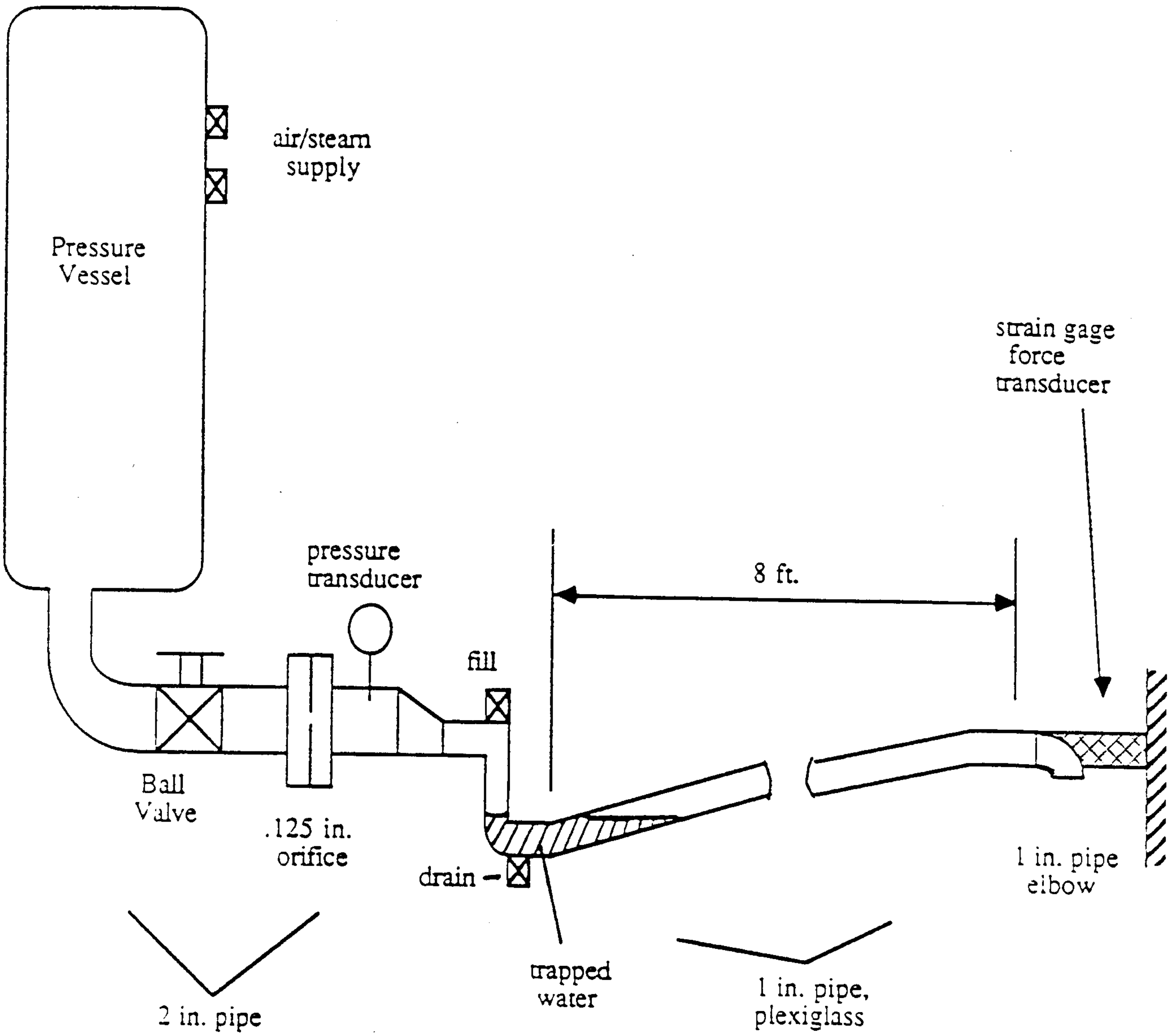


Figure 6-4. Schematic Diagram of the Experimental Apparatus Reference (4)

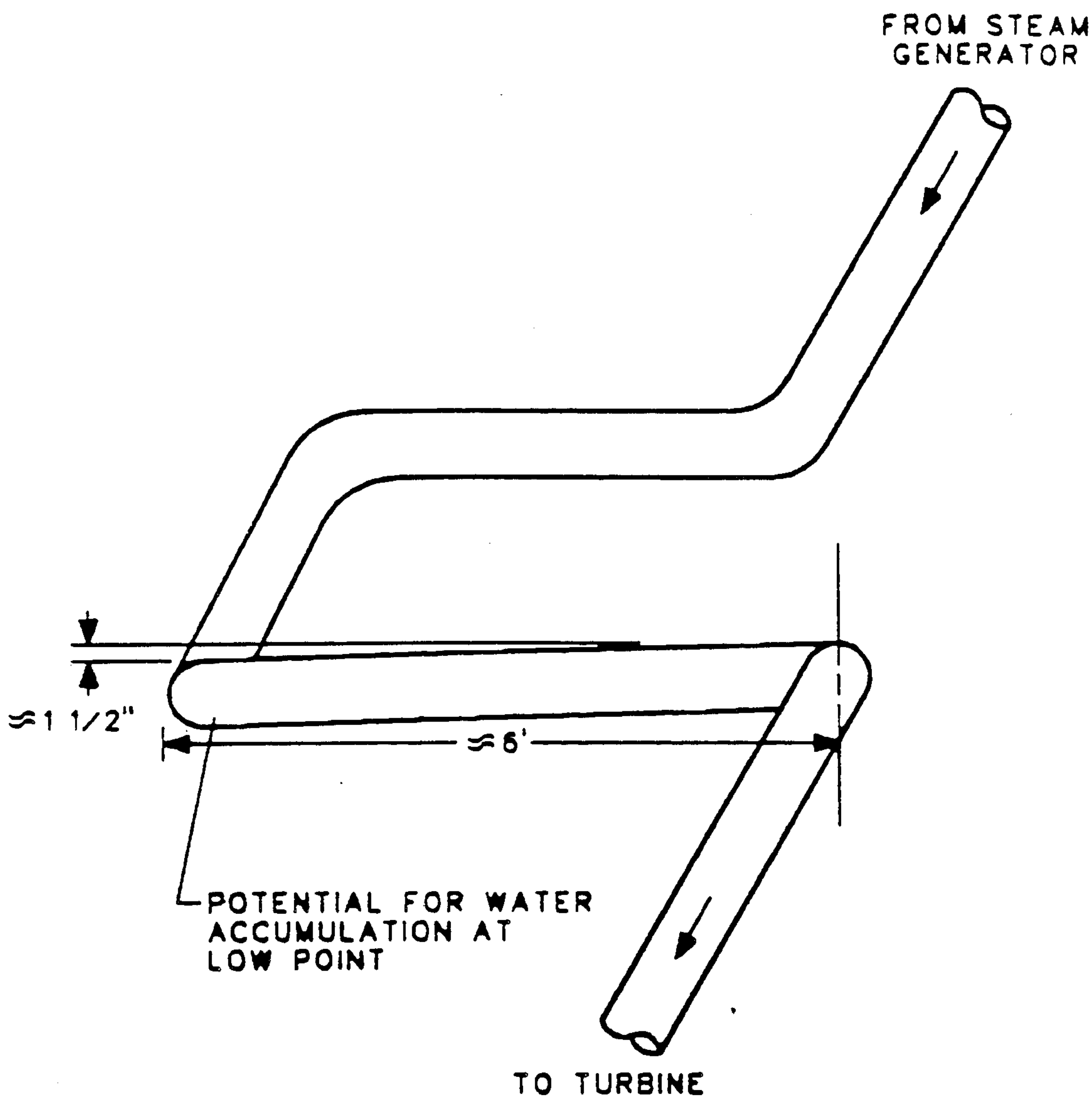


Figure 6-5. Section View of Auxiliary Turbine Steam Supply Line

Section 7

LOW PRESSURE SAFETY INJECTION SYSTEM IN PWR

SYSTEM FUNCTION

The Low Pressure Safety Injection System (LPSI), along with the High Pressure Safety Injection System (HPSI) and the Safety Injection Accumulators, provide emergency core cooling in the event of a pipe rupture in either the Reactor Coolant System (RCS) or Main Steam System.

Upon receipt of the Safety Injection signal, both the HPSI and LPSI pumps start. The HPSI pump injects borated water into the RCS and the LPSI pump operates on minimum flow recirculation back to the Refueling Water Storage Tank (RWST) through appropriate piping and valves. The LPSI pumps inject water into the RCS once the RCS pressure has decreased below the shutoff head of these pumps.

SYSTEM CONFIGURATION, MODE OF OPERATION AND COMPONENT DATA

Configuration

The LPSI System (see Figure 7-1) takes borated water from the RWST Tank and injects it into the RCS cold legs to cool the core in the event of an RCS break or Main Steam line break accident. Since the total developed head of the LPSI pumps is less than normal RCS pressure, this phase of emergency core cooling only takes place if the HPSI System cannot keep up with the RCS leak which results in a decrease in system pressure.

Mode of Operation

This event occurred during in-service testing of the safety injection pumps. The technical specifications require that the Safety Injection Pump be tested monthly to ensure the operability of the equipment. The tests repeatedly resulted in water hammer events which caused damage to several snubbers downstream of the LPSI pumps.

Component Data

- Low Pressure Safety Injection Pumps
- LPSI Pump Mini-Recirculation 4-in. Globe-Type Stop Check Valve
- LPSI Pump Discharge 10-in. Globe-Type Stop Check Valve
- LPSI Pump Suction Swing Check Valve
- LPSI Containment Isolation Valves
- LPSI Pump Mini-Recirculation Isolation Valve
- LPSI Pump Suction Isolation Valve

WATER HAMMER EXPERIENCE

In the 1970's a significant number of water hammer events were reported in LWR power plants. This is so, because many power plants were built and began commercial operation in this time period.

Each event was analyzed in the Task 2 Root Cause Report (1) to determine the areas of each system which are prone to water hammer, the specific water hammer mechanism, and root cause. The remedial actions taken by the utility to preclude future occurrence of a similar water hammer were described. Appendices A and B of (1) presented the BWR and PWR utility water hammer databases and Appendix C therein listed the utility plant codes used. Areas prone to water hammer were identified in typical schematics of each system discussed.

It has been determined that a cause of water hammer in low pressure safety injection systems is rapid valve closure. The valve in question is usually a pump discharge check valve that temporarily stuck open and then rapidly closed after start-up of a parallel pump.

The procedural and engineering factors contributing to the occurrence of this type of water hammer are:

- A lack of awareness concerning the possibility of water hammer events, their causes, and potential damages

- A lack of information available to the operator concerning the conditions in the system, to allow for proper action

- Inadequate design considerations for potential water hammer

One event that occurred in the LPSI system at a PWR power plant is briefly discussed below:

WATER HAMMER EVENT: PUMP STARTUP DURING TESTING

Event Description

During LPSI pump performance tests, a water hammer occurred in the discharge line of the standby pump (see Figure 7-1). The water hammer occurred as the test pump was started and the banging noise that was reported came from the standby pump cubicle area. This water hammer event had occurred repeatedly each time the test pump was started and it is known to have caused damage to some snubbers (rated load of 1,000 and 2,000 lb) located on the combined pump discharge header.

Mechanisms Responsible for the Event

Based on the characteristics of the LPSI system, the mechanisms which could have caused the water hammer are summarized as follows:

- Subcooled water entering a steam-filled pipe with subsequent steam bubble collapse

- Column separation with subsequent rejoining after pump start

- Rapid valve closure

A portion of the LPSI piping near the containment isolation valve may be filled with a steam bubble due to the back-leakage of the high temperature and high pressure reactor coolant fluid through the isolation valves. After the startup of an LPSI pump, subcooled water may enter the steam filled pipe and cause the steam bubble to collapse. However, since the high temperature interface is located just outside the containment structure, and all the damaged snubbers were located away from the containment, it is very unlikely that the event center could have originated from the collapse of the steam bubble just outside the containment.

The LPSI pumps take suction from the RWST, and the water level of the RWST tank is higher than any elevation of the piping in the LPSI system. This eliminates the possibility of the presence of any undetected voids in the LPSI system prior to pump start which may result in a column rejoining impact.

The automatic valves in the LPSI system consist of only the slow-acting motor-operated valves, and there are no extremely fast actuating valves in the system. The expected valve operation can only result in moderate hydraulic transient loads which have been incorporated into the system design for piping and equipment. Furthermore, based on the observation of plant personnel during the pump performance tests, as is described below, the most likely scenario for the water hammer event is caused by the rapid closure of the stuck-open check valve for one of the LPSI pumps.

Analysis of the Root Causes

Based on the accounts of plant personnel, the mechanical action which initiated these water hammer events is the starting of one of the LPSI pumps. Due to the temporarily stuck open stop check valve near the standby pump, which was rapidly closed by the reverse flow, pressure waves developed and propagated throughout the system causing damage to pipe support snubbers.

Supporting Evidence

Based on the accounts of plant personnel present during the pump tests and the characteristics of the snubber damage, the following evidence will support the scenario described for the water hammer event:

1. Among the snubbers which failed during the event, the size of those closer to the pump was larger than those farther away. This implies that the "event center" was closer to the pump.

2. Failed snubbers occurred almost entirely on the discharge pipe of one LPSI pump, but none failed on the other LPSI pump. When testing the alternate pump, no water hammer occurred, which suggests that the stop check valve of the other LPSI pump did not stick open, and thus did not cause a water hammer when the pump test was conducted.

3. Loud banging was heard during some of the tests, but was not heard in other tests. This implies that the stop check valve did not stick open all the time. However, when it did stick open, the water hammer occurred.

4. All horizontal snubbers of faulted load rating less than 6,800 lb located just downstream of the failed stop check valve were damaged during the event. This fact suggests that the dynamic load estimated below is possible.

Estimate of Dynamic Load

The location of selected snubbers at the LPSI pump discharge is shown in Figure 7-2. Post-event inspection of the damaged snubbers revealed that the snubber failures were caused by a sudden impact load, rather than vibration or mis-installation. The faulted load which could cause damage for each snubber is also shown in Figure 7-2. Based on this rating, it was estimated that the failed snubber located farthest from the pump discharge stop check valve experienced a water hammer load exceeding 525 lb. This load is equivalent to a pressure wave of only 10.5 psi in an 8-in. diameter pipe to which the snubber was attached.

According to the scenario described above, the pressure wave was developed by rapid closure of the stuck-open stop check valve at the pump discharge. The strength of the originating pressure wave will decrease as it propagates through the system encountering various pipe fittings.

The effects of pressure wave reduction due to pipe fittings has been investigated. Although pressure wave propagation in a complex piping system is a complicated phenomenon requiring sophisticated computer or physical modeling techniques, simplified equations are available for an order-of-magnitude estimate. This order-of-magnitude estimate for the impact load is usually very useful to help diagnose water hammer root causes.

For this purpose, the pressure wave reduction at an elbow can be estimated as follows (2):

$$R_{el} = 1-0.165\left[\frac{2}{\pi}(\pi-\Theta)\right]^{0.674} \mathrm{Exp}(-0.28\ r/D) \tag{7-1}$$

where R_{el} is the ratio of the final and incipient pressure waves at the elbow. Θ is angle of the elbow in radians. r and D are the radius of the elbow and pipe diameter, respectively. For a typical 90 degree elbow with $r/D = 5$, R_{el} is calculated to be about 0.96, which means that the strength of the pressure wave is reduced approximately 4 percent whenever it encounters a 90 degree long-radius elbow.

The pressure wave strength will also be reduced as it passes across a tee or a branch connection as follows (3):

$$R_{br} = 2A_i/(\Sigma A_j) \tag{7-2}$$

where R_{br} is the ratio of the final and incipient pressure waves at the branch, A_i is the pipe area of the incipient wave, and ΣA_j is the total pipe area at the branch. For a typical three-way branch of equal pipe size, R_{br} is calculated to be 0.67, which indicates that the pressure wave loses approximately 33 percent of its strength when it propagates through a typical tee junction.

The attenuation of pressure waves at a reducer can be handled as a special case of the branch connection. Since a reducer includes only two pipes of different size, the ratio of the pressure waves at the reducer (R_{re}) can be expressed as follows (3):

$$R_{re} = 2A_i/(A_i + A_f) \tag{7-3}$$

where A_i and A_f are the pipe areas before and after the reducer.

Based on the piping configuration (Figure 7-2), there are about twenty-eight (28) long-radius 90-degree elbows, five (5) tees, and four (4) reducers along the piping between the pump discharge stop check valve and the location of the failed snubber farthest away from the pump. Using the above equations for the pressure wave attenuation, it can be estimated that the pressure waves lose a total of 68 percent of their strength after encountering the elbows. Likewise, the magnitudes of the pressure waves are reduced by 77 percent and 2 percent due to tees and reducers, respectively. The originating pressure wave could further be reduced as it passed through the heat exchanger. However, its effects are not included in this analysis due to lack of detailed data for the heat exchanger.

Thus, the overall effect of elbows, tees, and reducers between the stop check valves and the failed snubbers remote from the pump discharge results in a total reduction of approximately 93 percent of the originating pressure waves. Since the pressure wave at the location of the last failed snubber in the system was estimated to be approximately 10.5 psi, the originating pressure wave due to rapid closure of the stop check valve is therefore estimated to have been 150 psi. This pressure wave could result in a fluid dynamic force of approximately 11,800 lb on a 10-in. diameter pipe segment.

Based on Joukowsky's elastic wave theory using a wave speed of 4,000 ft/s, this pressure wave corresponds to a sudden stoppage of a flow velocity of 2.8 ft/s, or 685 gpm in a 10-in. diameter pump discharge pipe. The LPSI pump mini-flow recirculation line upstream of the stop check valve (see Figure 7-1) is designed to recirculate up to 2,000 gpm. Therefore, it is very likely that after an LPSI pump starts, the stuck-open stop check valve could have passed up to 700 gpm of reverse flow through the mini-flow recirculation line of the idle pump back to the refueling water storage tank when the valve disc closed suddenly, resulting in the observed water hammer event.

Inspection of the Stop Check Valve

The utility had concluded that the pump discharge stop check valve was the initiator of the water hammer event. They revised the test procedures to avoid the water hammer. The original test procedure required that the operator simply confirm the valve lineup and start the pump. (This is when the water hammer was originally observed.) To prove that the discharge stop check valve on the standby pump was causing the water hammer, the test procedure was revised to first cycle the stop check valve shut to ensure that the valve disc was properly seated and then return the hand-wheel and the valve stem to the full open position. The parallel pump was then started with the expectation that the water hammer would not occur with the revised test procedure. However, it did occur and damaged additional snubbers.

One of the LPSI pump discharge stop check valves was subsequently disassembled for inspection. It was noted that the valve disc was stuck on the valve stem, and moved along with the valve stem. Further inspection revealed that the end of the valve stem had deformed due to over-torquing of the valve when it was closed (see Figure 7-3). The deformed valve stem within the valve disc housing would not seat the valve disc firmly even with the extra precaution to do so in the revised test procedure.

Corrective Measures

To prevent further snubber damage during pump performance testing, the utility revised the test procedure to require that the discharge stop check valve of the pump not being tested be shut and remained in the shut position prior to starting the test pump. Additionally, provisions were to be made to either reduce the clearance between the valve stem and disc guide to prevent the valve disc from being cocked, or change the valve stem and disc material to a tougher material, or replace the present stop check valve with a gate valve and a tilting disc check valve in series.

SYSTEM EVALUATION

Normal Transients

There are expected water hammer transients that LPSI systems are typically designed for such as pump startup or trip. Most systems are not designed to accommodate water hammer loading that may be caused by improper valve operation, such as a temporarily stuck open check valve.

Severe Transients

The most likely severe water hammer transient is a stuck-open rapid check valve closure upon parallel pump startup with reverse flow through the normally closed check valve. This piping system is not normally designed to withstand this type of water hammer, because the postulated water hammer event is based on an active failure of a lift check valve.

REVIEW OF OPERATING, TESTING, AND MAINTENANCE PROCEDURES

Operating Procedures

The utility revised the operating procedure when testing the start-up capability of a LPSI pump by requiring that the discharge check valve of the parallel standby pump be manually closed prior to starting the test pump. This obviously eliminated the pump discharge stuck-open check valve scenario for systematic LPSI pump startup.

Testing Procedures

The post-water hammer event revision to the testing procedures requires that the standby LPSI pump discharge stop check valve be closed (and remain closed) prior to starting the parallel LPSI pump being tested.

Although this revision to the operating procedure may be adequate for testing purposes, this practice may result in the following two long range problems:

1. The stop check valve could be left shut after the test, which could effect the startup of the corresponding pump in the event of a need for emergency core cooling.

2. If the LPSI pumps were needed quickly, a water hammer of the type described could occur and if so it could damage many of the snubbers.

Maintenance Procedures

A new required maintenance procedure is to periodically ensure that the pump discharge lift check valve disc opens and closes as designed.

STRENGTHS AND WEAKNESSES FOR WATER HAMMER PREVENTION

Strengths

One strength of the system design is that the RWST water level is higher than the system piping elevation thus ensuring that the system is water solid at all times. This prevents a possible Mechanism 7 type water column separation and rejoining water hammer.

Weaknesses

The presently designed system configuration should allow for the installation of an isolation valve in series with a LPSI pump discharge check valve to prevent reverse flow due to a stuck-open check valve and to allow for pump isolation during testing and operation of another pump. This would relieve the currently installed check valve from its unintentional dual purpose of isolation and closure during pump trip. It is noted that this isolation valve must open when emergency core cooling is needed.

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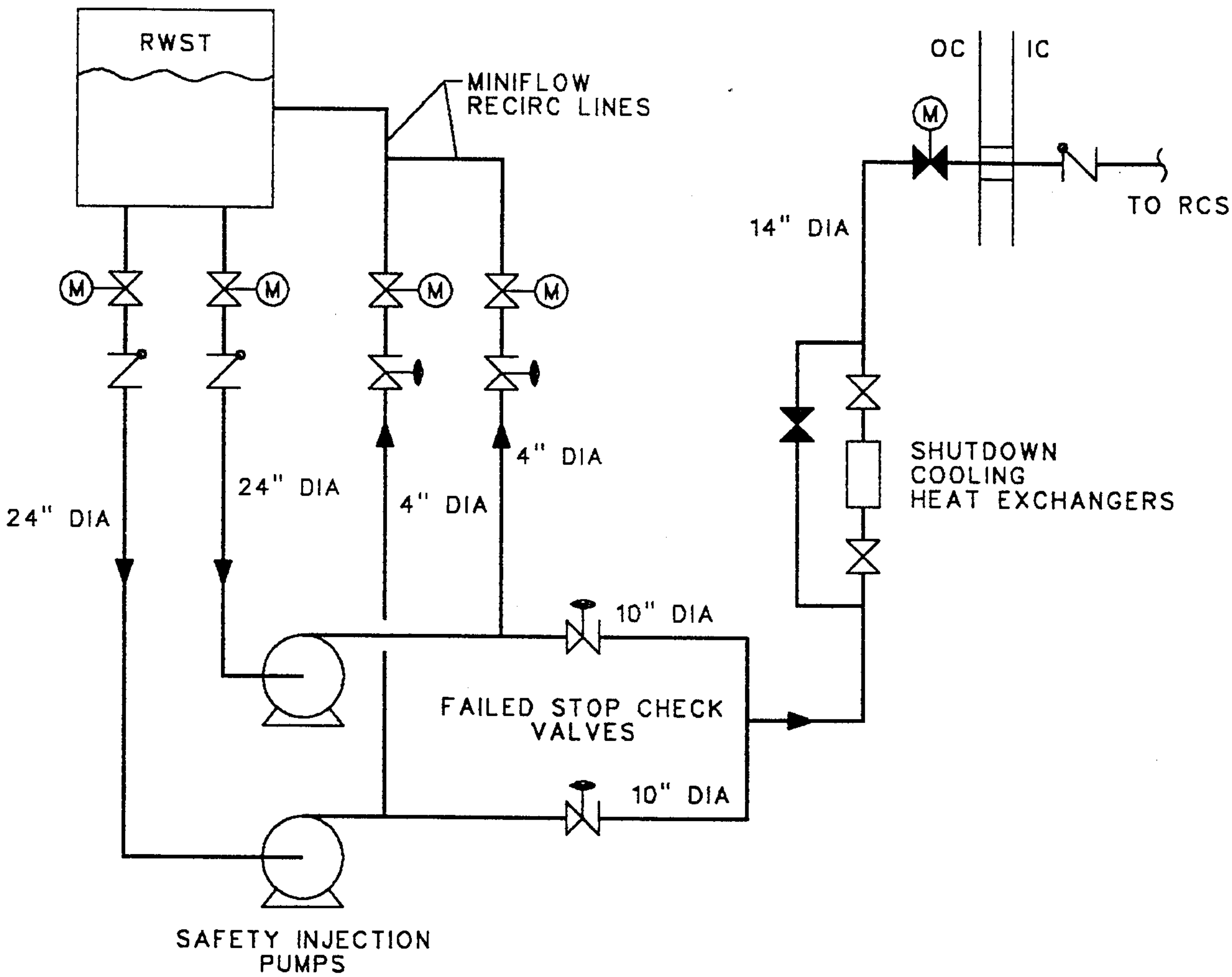
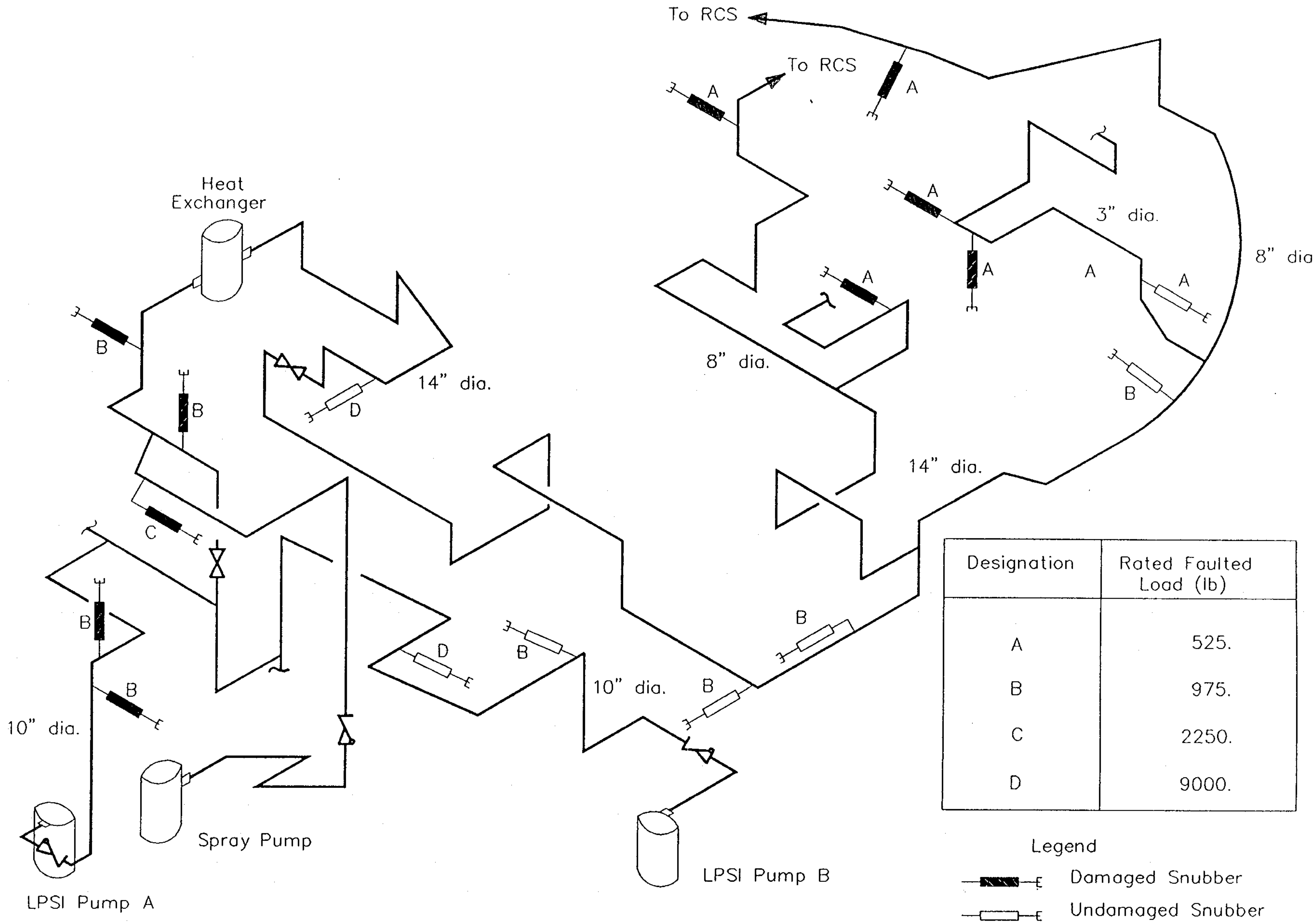


Figure 7-1. Simplified Schematic for
Low Pressure Safety Injection System



Designation	Rated Faulted Load (lb)
A	525.
B	975.
C	2250.
D	9000.

Figure 7-2. Simplified Isometric Diagram Showing Snubber Failures

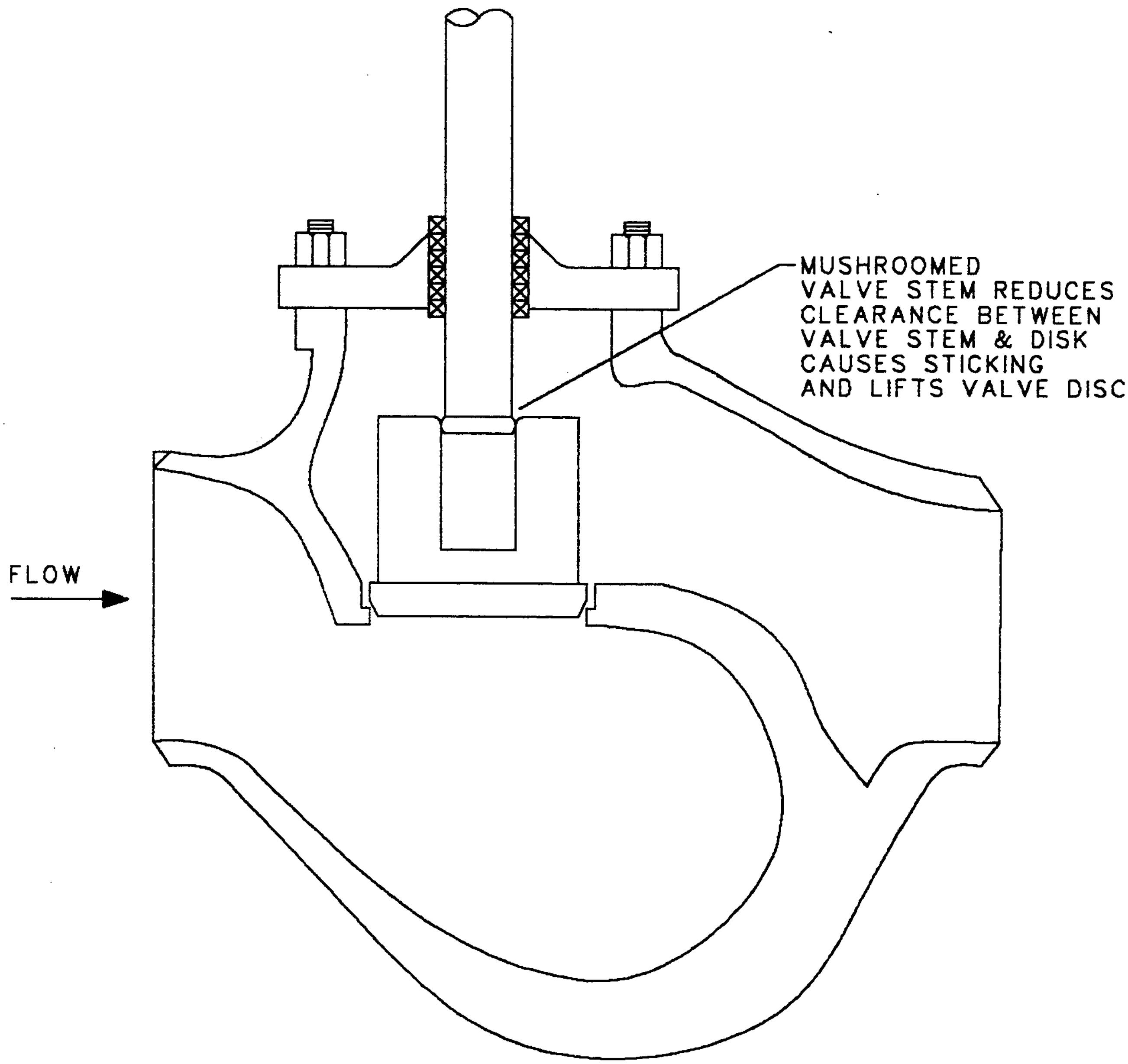


Figure 7-3. Safety Injection Pump Discharge Stop Check Valve

Section 8

RESIDUAL HEAT REMOVAL SYSTEM IN PWR

SYSTEM FUNCTION

The Residual Heat Removal (RHR) system transfers heat from the Reactor Coolant System (RCS) to the Component Cooling Water System (CCWS) to reduce the reactor coolant temperature to the cold shutdown condition at a controlled rate during the latter part of normal plant cooldown. It also maintains this temperature until the plant is started again.

As an additional function, it is also a part of the Emergency Core Cooling System (ECCS) during the injection and recirculation phases of a Loss of Coolant Accident (LOCA). This safety function is to provide emergency core cooling and negative reactivity insertion in the event of a loss of primary or secondary coolant. The RHR system is normally lined up for this emergency operation in which water from the Refueling Water Storage Tank (RWST) is injected into the Reactor Coolant System (RCS) at low pressure when required. Accident signals start the system automatically. Manual start capability is also provided. The two separate flow paths (loops) provide redundant capability of meeting the safeguards function of the RHR system. The loss of one RHR system flow path would not negate the capability of the ECCS since the two flow paths each inject into all four RCS cold legs.

The RHR system is also used to transfer refueling water between the RWST and the refueling cavity before and after the refueling operations.

SYSTEM CONFIGURATION, MODE OF OPERATION AND COMPONENT DATA

Configuration

Figure 8-1 shows a simplified schematic diagram of the RHR system. The system consists of two loops with some portions of the piping being common. There are two RHR heat exchangers, two pumps, and associated piping, valves, and instrumentation necessary for proper operation and control. The inlet line of the RHR system is connected to the hot leg of RCS loop 4, while the return lines are connected to the cold legs of each of the RCS loops.

Two motor operated valves in series isolate the RHR from the RCS on the suction side whereas two check valves in series perform the same function on the discharge lines (see Figure 8-2).

The RHR pumps can take suction from the following four sources:

- Refueling water storage tank
- Refueling cavity
- Containment Recirculation sump
- RCS hot leg number 4

In addition to discharging the flow to the RCS hot or cold legs, the RHR pump discharge flow can also be routed to the spent fuel pool, RWST and a portion of it to the RCS via the letdown heat exchanger.

Figure 8-2 is an elevation diagram for the RHR system at the plant reviewed showing the system approximately to scale in the vertical direction but not in the horizontal direction. The various main system vents, drains, valves etc. are shown.

RHR System Operating Modes

Normal Operation (Plant Cooldown)

In this mode the RHR system provides long-term cooling during normal plant cooldown once the RCS temperature and pressure are reduced below 350°F and 400 psig, respectively. This would occur about 4 hours after reactor shutdown. The RHR pump take suction from hot leg number 4 and return the flow to the cold legs via the tube side of the RHR heat exchangers through the safety injection system cold leg injection headers. The Component Cooling Water system removes the heat on the shell side of the RHR heat exchangers. At the start of this cooldown phase, the RHR pumps are started and run on their mini flow circuits for about

5 minutes while monitoring the RHR system boron concentration level. If the boron concentration in the RHR mini flow line is less than in the RCS, the RHR suction is realigned to the RWST and discharge to the Chemical and Volume Control System (CVCS) holdup tanks until the boron concentration is equal to or greater than that of the RCS. When such a condition is established, the RHR pumps are stopped and the system realigned to take suction from the number 4 hot leg and discharge into the cold legs. The flow to RCS is gradually increased to prevent thermally shocking the pipe and the nozzles. The RCS cooldown rate is maintained by regulating the RHR heat exchanger flow via valves HCV-606 and HCV-607. Constant RHR total flow is also maintained by regulating the RHR heat exchanger bypass valve HCV-618. With both RHR pumps operating (pumping 5000 gpm to each heat exchanger), the RHR system takes about 20 hours to reduce the RCS temperature to 140°F. Then one RHR pump and heat exchanger may be taken out of service.

Plant Startup

During plant startup the reactor is brought from cold shutdown to no-load operating temperature and pressure. The RCS is completely filled at the beginning of the startup operation and the pressurizer heaters are energized to heat the pressurizer to saturation. The RHR system is used to control RCS pressure in this mode by throttling the valve HCV-128 (see Figure 8-3) so as adjust the letdown flow. The letdown flow is then gradually increased to reduce the pressurizer level to its no-load value. Once this is achieved the reactor coolant pumps are started and the plant heatup initiated. The RHR pumps are then stopped, and when the plant pressurization to normal operating pressure is started, the RHR system is isolated and realigned to its normal standby mode for ECCS injection.

Refueling

Before the refueling begins, one RHR pump is used to pump borated water into the refueling cavity from the RWST. The reactor vessel head is lifted slightly and the RHR water flow into the vessel through the cold legs up into the refueling cavity past the open reactor vessel flange. After sufficient level is attained in the refueling cavity, the RHR pump is stopped, the suction line realigned to the hot leg loop 4 and the normal RHR duty resumed.

During refueling the RHR system performs its normal decay heat removal function. A portion of the RHR flow is directed to the CVCS for purification and returned to RCS via the charging pumps.

After refueling, the RHR pump B is used to drain the refueling cavity via the Spent Fuel Pool Cooling System (SFPCS) connection to the top of the reactor vessel, pumping water from the refueling cavity to the RWST as the reactor head is lowered into place. When the reactor head is in place, the RHR decay heat removal duty is resumed.

Emergency Operation - Injection Phase

During normal plant operation the RHR system is lined for ECCS duty. This system is actuated either manually from the control room or automatically when the DBA sequencers receive their respective Safety Injection Signal. The RHR pumps take suction from the RWST through normally open motor operated valves MO-8812 and MO-8700 (see Figure 8-3). One or both pumps can be operational and when the RCS pressure drops below about 200 psig, borated water from the RWST is injected into the cold legs of the RCS through normally open valves HCV-606, HCV-607, MO-8716 and MO-8809.

If the RCS pressure remains above the RHR pump shutoff head the RHR miniflow line protects the pump from overheating until such time as the RCS pressure falls below the pump shutoff head. For long term RHR pump operation at shutoff head the CCWS removes heat through the RHR heat exchanger to prevent pump overheating.

The injection phase for the RHR system is terminated when the RHR pumps are tripped automatically on RWST low level alarm. At this time sufficient water should exist to provide the required NPSH for the RHR pumps to operate in recirculation phases.

Emergency Operation - Cold Leg Recirculation Phase

Immediately after the termination of the injection phase the operator initiates cold leg recirculation by aligning the RHR pump suction to the containment recirculation sump and restarting the RHR pumps. In this mode the water that collects in the containment sump is cooled in the RHR heat exchangers and returned back to the core. In addition to discharging to the RCS cold legs, the RHR pumps discharge is also lined up to the suction of the Centrifugal Charging Pumps (CCP) and Safety Injection Pumps (SIP). This is because sufficient NPSH does not exist for the CCP and SIP to take suction from the containment recirculation sump. If the RCS pressure is below the RHR pump shut off head, all ECCS pumps feed simultaneously into the core. Otherwise, flow from the discharge of the RHR pump goes to the suction of the remaining ECCS pumps providing them with the required NPSH so that they can perform their function.

Emergency Operation - Hot Leg Recirculation Phase

The hot leg recirculation mode is initiated manually by the operator at approximately 13 to 17 hours after the start of the cold leg recirculation. This mode is similar to the cold leg recirculation except that the RHR and SI pump discharge flow is directed to the RCS hot legs. Hot leg recirculation acts to reduce core boric acid concentration by reversing SI flow through the core which tends to flush out the higher concentration solution.

Interfaces with Other Systems

a) Reactor Coolant System (RCS): The primary function of the RHR system is to remove the decay heat from the nuclear reactor core by injecting coolant into the cold or hot legs of the RCS.

b) Emergency Core Cooling System (ECCS): The RHR system is part of the two independent trains of the ECCS each comprising a centrifugal charging pump, a safety injection pump, a RHR pump and heat exchanger, and a flow path capable of taking a suction from the RWST on a safety injection signal and of transferring suction to the containment recirculation sump during the recirculation phase of operation.

c) Chemical and Volume Control System (CVCS): The RHR system pump discharge connects to the CVCS upstream of the letdown heat exchanger. During normal operation, a portion of the RHR flow is directed to the CVCS for purification. During plant startup the RHR flow to the CVCS is used to control RCS pressure.

d) Spent Fuel Pool Cooling System (SFPCS): The RHR system is capable of providing emergency cooling for the spent fuel pool. Piping is provided from the RHR crosstie line to supply the spent fuel pool cooling system should both of the spent fuel pool pumps become inoperable.

e) Component Cooling Water System (CCWS): The CCWS is connected to the shell side of the RMR heat exchangers and therefore removes the decay heat from the reactor core by cooling the RHR system fluid.

f) Containment System: The cold and hot leg recirculation modes of the RHR system operation provide long term core cooling in the case of a LOCA. The RMR pump suction is taken from the containment system's recirculation sump to pump this liquid into the core.

g) 4160V Electrical System: The RHR pump motors are powered from separate 4160 volt safeguard electrical buses. If a total loss of preferred power occurs while the system is in service, each bus is automatically transferred to a separate emergency diesel power source.

i) Other Systems: In addition to the major systems noted above, the RHR system interfaces with other systems such as the instrument air system, other electrical systems, etc.

Control Logic

Automatic System Operation

The RHR system is normally lined up for coolant injection mode when the reactor is operating in power generation mode. Both the RHP pumps start automatically when the DBA sequencers receive their respective Safety Injection (SI) signal generated by any of the following:

- Low pressurizer pressure.
- High containment pressure.
- High differential pressure between any two steam generators.
- High steam line flow coincident with low steam pressure or low-low average steam temperature.
- Manual action.

The RHR pumps trip automatically under the following conditions:

- 4160V bus undervoltage that supplies power to the RHR pumps.
- RHR motor overcurrent.
- RWST low water level (50.9 percent)

Manual System Operation

The RHR pumps can also be started manually either from a local panel or remotely from the control room. The manual start is utilized for the non coolant injection operating modes.

Instrumentation and Alarms

The following instrumentations and alarms are provided for the RHR system:

- RWST level transmitters for Low and High level trips and temperature switches to keep the RWST minimum temperature at 37°F.

- RHR hot leg suction line pressure, hot and cold leg flows. The valves MO-8701 and MO-8702 are interlocked such that they cannot open if RCS pressure exceeds 425 psig. Also these valves close if this pressure is equal to 600 psig.

- RHR pump discharge orifice flow switches provide a signal to open or close pump miniflow line valves HCV-610 and HCV-611. These valves open when flow is 500 gpm and close when flow is 1000 gpm.

- RHR pump suction and discharge pressure. High pressure alarm alerts the operator to verify proper operation upon an SI signal.

- RHR heat exchanger discharge temperature indication.

Valve Interlocks

Valves MO-8700 A/B on RHR & RWST hot leg suction line are interlocked with MO-8811 from containment recirculation sump such that MO-8700 cannot open unless MO-8811 is closed. Similarly, MO-8811 cannot be opened unless MO-8700 is closed. This prevents inadvertent flow from RCS into the recirculation sump.

Valves MO-8701/MO-8702 on the RHR hot leg suction are interlocked with MO-8812 from the RWST such that MO-8701/MO-8702 cannot open unless MO-8811 is closed. This prevents inadvertent flow from RCS into the RWST. They receive an "open permissive" signal when RCS pressure is less than 425 psig. Further, MO-8701/MO-8702 cannot be opened unless RCS pressure is less than the RHR design pressure (600 psig)and they close if RCS pressure exceed 600 psig. Failure of power supply to these valves leave them in "as is" position.

Valves MO-8804 A/B from the RHR to CCP/SI pump suction are interlocked with MO-8701 and MO-8702. MO-8804 cannot be opened unless MO-8701/MO-8702 are closed. This prevents inadvertent draining of RCS to RWST.

Filling, Venting, and Draining

The RHR system is provided with a number of vents and drains for removing and returning to service components and portions of piping. Two valve isolation or capped connections are used.

The RHR system is protected against overpressure. The inlet line to the system is equipped with a pressure-relief vale sized to relieve the combined flow of all the charging pumps at the relief set pressure. Each discharge line to the RCS is also equipped with a pressure-relief valve to relieve the maximum possible backleakage through the valves separating the RHR system from the RCS system. The capability of the pressure-relief valves is in excess of the design leakage associated with the check valves in each of the discharge lines.

Component Data

Component data for major valves in the system are tabulated in Table 8-1. Data on pumps and heat exchangers are given in Tables 8-2 and 8-3, respectively. The pump characteristic curve is shown as Figure 8-5.

WATER HAMMER EXPERIENCE

In the 1970s a significant number of water hammer events were reported in LWR power plants. Since 1978, the NRC has sponsored studies to evaluate the causes and recommend corrective measures to prevent or mitigate water hammer damage. (1), (2), and (3) reviewed the above issues in detail. Since 1982 more events have been reported and these have been compiled under Task 2 of this project (4).

Each event was analyzed in the Task 2 Root Cause Report (4) to determine the areas of each system which are prone to water hammer, the specific water hammer mechanism, and root cause. The remedial actions taken by the utility to preclude future occurrence of a similar water hammer were described. Appendices A and B of (4) presented the BWR and PWR utility water hammer databases and Appendix C therein listed the utility plant codes used. Areas prone to water hammer were identified in typical schematics of each system discussed.

The procedural and engineering factors contributing to reported events include:

- Equipment malfunctions, including unintended use and maintenance-related failures of components
- Inadequate design consideration of potential water hammer under all modes of system operation and testing
- Inadequate venting procedures
- A lack of awareness concerning the possibility of water hammer events, their causes and the potential damages

Three events that occurred in the residual heat removal system in PWR power plants are briefly discussed below:

WATER HAMMER EVENT 1: TRANSIENT IN THE LETDOWN LINE UPON FLOW INITIATION

Event Description

This water hammer event occurred early during the plant's operational life in the 2-in. diameter low pressure letdown line which damaged a total of 34 hangers out of 37. Figure 8-4 shows the area where support damage occurred. This happened when the letdown line was being placed into service. Since the event occurred such a long time ago and records of the event scenario details are not available, it is not known if this event occurred during plant startup or the start of the cooldown phase.

Mechanisms Responsible for the Event

The mechanism responsible for this event is the voiding of portions of the letdown line when it is isolated, followed by the collapse of this void when the line is brought into service again, Mechanism 7.

Analysis of the Root Causes

The letdown line from the RHR system meets the CVCS system at a high elevation after valve HCV-128 as shown in Figure 8-2. Discussions with the plant personnel indicated that once the letdown line is isolated from the RHR system, leakage through valves and to the Volume Control Tank would cause flashing of the water in the letdown line and the generation of steam voids. At that time the RHR system was taken off line when the RCS temperature was above 200°F. Consequently, any depressurization through leakage from the HCV-128 valve to the low pressure letdown system was cause voiding of the letdown line.

At the time the event occurred, the letdown line flow was initiated by opening a on/off gate valve and not in a controlled manner using a throttle valve as is being done currently. There was no provision of venting the line prior to the start of flow. As seen from Figure 8-2, due to the piping configuration there would be a dead leg of water that would contain valve HCV-128, once there is void formation in the letdown line. The filling water would collapse the void by impacting the dead leg.

Estimate of Limiting Dynamic Load.

An estimate of the filling velocity and hence the forces due to the impact of a water column against a dead water leg or a closed valve can be made in an approximate way as follows:

The piping equivalent length from the RHR pumps to the voided space is estimated to be about 135 ft of 2-in. pipe. This includes the fittings losses but not any control valve throttling. This is equivalent to a loss coefficient "k" of about 16 based on 2-in. diameter. From Figure 8-5 (RHR pump curve) it is seen that the pump total head is about 400 ft of water over a range of flow from zero to 2500 gpm. Also from Figure 8-2 it is obvious that all this head is needed to overcome friction and other losses and not elevation. Therefore, for a "k" of 16 and pressure difference of about 400 ft of water, the filling velocity in a 2-in. pipe is about 40 ft/s. Using Joukowsky's elastic wave equation, the pressure rise due to the impact of the filling with a dead water leg is estimated to be about 1200 psi. In a pipe segment of 2-in. diameter, the corresponding fluid dynamic force is about 4.0 kips. This is a significant force in a small diameter line. If the void formation is such that there is vapor next to the closed valve MO-128, then the void collapse would be against a closed valve. In such a case the peak forces would be of the order of 8 kips. At the time of the incident the forces required to cause the observed damage were estimated to be in the 5 to 16 kip range which are in fair agreement with the above approximate calculation.

Corrective Measure Taken

After the repair of the damaged supports, two measures were taken to minimize the water hammer event from recurring. The first is the addition of throttle valve in the line that is opened slowly to fill the line in a controlled manner. This valve is shown in Figure 8-2 as motor operated valve 1363. The second action requires the venting of the low pressure letdown line using the vent just before valve HCV-128 before valve 1363 is completely opened.

WATER HAMMER EVENT 2: INADVERTENT CLOSURE OF THE RHR PUMP SUCTION VALVE

Event Description

This event was discovered by the damage caused after an inadvertent closure of the RHR pump suction valve MO-8701 (see Figure 8-2) while pump A was running. It resulted in the failure of two hangers in the low pressure letdown line to the CVCS system, two improperly loaded supports in the RHR pump A miniflow line and failed anchor bolts on one support in the RHR discharge line downstream of the train A RHR heat exchanger. All the damage was in the same RHR train (train A) and none in the other train. This event occurred some time ago and details of the transient scenario are not well documented. Detailed information regarding the event could not be obtained from the plant operators. Train A was in operation at the time of the event pumping water from the hot leg of the RCS to the cold leg during the plant cooldown mode.

Mechanism Responsible for the Event

The mechanism responsible for this event is most probably the voiding of portions of the suction line due to the closure of the RHR pump suction valve and the subsequent void collapse after the pump was tripped due to reverse flow through the pump and through the mini flow line.

Analysis of the Root Causes

Train A of the RHR system was running in test mode when the RHR suction valve MO-8701 from the RCS automatically closed. MO-8701 is a relatively slow closing valve (120 s). A blown fuse in the solid state protection system caused the valve to close. The RHR pump A ran for approximately 30 s to 1 minute without suction before being turned off. Although a recirculation flow path is provided through FCV-610 in the pump miniflow line, it takes some finite time for the this valve to open and establish flow in the miniflow line. Also due to low recirculation flow and because of the geometry of the suction line, column separation may have occurred in the suction line. By the time the pump is tripped the miniflow valve FCV-610 would be open. Flow through the miniflow line and any reverse leakage flow through the pump discharge check valve would tend to collapse the cavity giving rise to water hammer.

Estimate of Limiting Dynamic Load.

The estimation of the void collapse pressure requires the calculation of the velocity at which the water impacts the closed valve MO-8701. When the pump trips, the void begins to collapse as the pump discharge pressure fills the suction line via the recirculation line. However, as the pump coasts down, this driving pressure decreases. Therefore, without performing a detailed analysis it is not practical to estimate the filling velocity for this situation. A highly conservative estimate can be made if one assumes that at the time of void collapse, the pump discharge pressure is about the same as the pump shutoff head (minus the elevation head of the valve) and the pressure in the void. For water at about 200 °F, this driving head is about 310 ft of water. The 3-in. miniflow line is about 46 ft long. Considering the fittings losses and the valve FCV-610 to be fully open, the equivalent "k" value of the filling flow path is estimated to be about 12 based on 3-in. pipe diameter. By a method similar to the that for event 1, this gives a filling velocity of about 9 ft/s in the 14-in. line. The resulting impact pressure surge using Joukowsky's relationship is about 525 psi and the corresponding force on a pipe segment with 14-in. diameter is about 81 kips. On a pipe segment of 3-in. diameter the peak force would be about 4 kips. Of course, this is an over estimate since the impact velocity is expected to be much smaller than that calculated above. If one assumes that the filling velocity is about 10 percent of the rated RHR pump flow, then the peak force would be about 6 kips in a 14-in. diameter pipe segment.

Corrective Actions Taken

The corrective action taken was the repair of the damage. Since the event was an isolated, non-recurring event their was no system or procedural changes were made to the RHR system.

WATER HAMMER EVENT 3: CLOSURE OF THE RHR PUMP RECIRCULATION FLOW CONTROL VALVE

Event Description

This was not an isolated event but used to occur repeatedly when the RHR system was in the decay heat removal mode with the reactor level reduced to the hot leg level. Discussions with plant personnel have indicated that they had experienced water hammer problems in the 3-in. RHR pump recirculation (miniflow) line over several years. A number of pipe supports on this line have suffered failure.

Mechanisms Responsible for the Event

The mechanism responsible for these events was rapid valve actuation of a control valve.

Root Cause Analysis

The flow velocity in the 3-in. RHR pump miniflow line can be very high (about 50 ft/s) if the pump is running in a recirculation mode and the miniflow line maximum flow is 1000 gpm. Under these conditions an inadvertent closure of the miniflow control valve, whose stroke time is relatively short (opens in 8 s and closes in 6 s), from a position of nearly closed valve can result in a significant water hammer load. This was happening when the reactor vessel was partially drained and the water level in the RCS hot leg (where RHR takes suction) decreased to a value that permitted air to be drawn into the RHR suction line due to flow vortexing at the RHR hot leg suction. It was postulated that as this air passed into the RHR pumps, it caused the RHR pump flow to fluctuate. Amperage fluctuation observed in the RHR pump power supply confirm this. The flow control valve HCV-610 or HCV-611 in the pump miniflow flow line is controlled by the RHR pump discharge flow. This valve would open if the water-air mixture in the RHR pump discharge gives a low flow indication signalling it to open. Note that this valve will open if the RHR pump discharge flow is less than 500 gpm and close if it exceeds 1000 gpm. Fluctuation in the indicated RHR pump flow could make the miniflow control valve to open and close in a cyclic fashion causing pressure surges and consequent support damage.

Estimate of Limiting Load

Assuming a sudden valve closure in the miniflow line when the flow is the minimum recirculation flow of 500 gpm, one can estimate the peak dynamic load. The flow velocity in the 3-in. line at 500 gpm flow is about 22.4 ft/s. Using Joukowsky's relationship, the peak pressure corresponding to stopping this flow instantaneously is about 1342 psi. Thus the peak force on a pipe segment of 3-in. diameter would be about 9.5 kips. The longest pipe segment in the miniflow line is about 32 ft. If one assumes a valve closure time during the valve cycling of about 0.1 s, this segment would experience a peak force of about 680 lb.

Corrective Actions Taken

Recognizing that vortexing at the hot leg suction could lead to loss of RHR, instrumentation and a TV camera were installed to carefully monitor the water level, and maintain it at elevation 60 ft-4 in. The plant operators found that vortexing could be avoided if the water level and the RHR suction flow are maintained above 60 ft-4 in. and below 3500 gpm, respectively. Currently the reactor vessel is not drained until the decay heat is such that the RHR flow requirement is below 3000 gpm. After taking these precautions the plants personnel indicated that damaging water hammer has not recurred in the miniflow lines.

SYSTEM EVALUATION

Normal Transients

The RHR system piping supports in the plant reviewed were not sized for any fluid transient loads. From Table 8-1 that gives the RHR valves data it is seen that some of the RHR valves have rather short actuation times. For example, MO-8700 which is in the 14-in. RHR pump suction line from hot leg 4 and the RWST, is a gate valve that has a maximum stroke time of 17 s. Recognizing that for a gate valve the effective opening/closing time is much shorter than the total stroke time, this valve is a relatively quick opening/closing valve. However, the RHR system operating procedures for this plant show that except for the RHR heat exchanger flow control and bypass valves (HCV-606, HCV-607 and HCV-618), all the other valves are aligned/operated when the RHR pumps are off. Furthermore, these procedures do point out that HCV-607, HCV-608 and HCV-618 should be actuated very slowly. Thus, the system should not see any significant "normal operating hydraulic transients."

Severe Transients

The most common "unanticipated" severe water hammer problems encountered in PWR RHR systems are related to Mechanisms 3 (steam pocket collapse) and 7 (column rejoining). The RHR system configuration at the plant reviewed (see Figure 8-2) is such that all the sources and sinks for the RHR flow are situated at a much higher level than the pumps and other system equipment. This keeps the system normally full and avoids the line voiding problems by draining. This is generally true for PWRs as compared to BWRs where the number of water hammer problems in RHR systems are much larger. However, when the system (or portions of the system) is drained for maintenance related work, problems should not be encountered as long as proper venting procedures are followed when refilling the system. The only commonly used system that interfaces with the RHR system is the CVCS through the low pressure letdown line. From Table 8-1 it can be seen that the flow velocity in the RHR pump miniflow line can be very high if the pump is running in a recirculation mode and the miniflow line maximum flow is 1000 gpm. Under these conditions an inadvertent closure of the miniflow control valve, whose stroke time is relatively short, can result in a significant water hammer load generation. Therefore, it would be prudent to keep this valve well maintained.

When the RHR system is not operating in the plant cooldown mode, the Valves MO-8701 and MO-8702 isolate the hot high pressure RCS fluid from the colder lower pressure RHR system fluid. Any leakage of the RCS fluid through the MO-8702 valve would cause a steam bubble to form between the two valves. Of course, for this to happen MO-8701 will also have to leak. However, if this happens, the steam pocket will collapse causing a water hammer (Mechanism 3) when MO-8702 is first opened to bring the RHR into service for plant cooldown duty. Maintaining the two valves MO-8701 and MO-8702 so that don't leak will prevent this potential problem.

REVIEW OF OPERATING, TESTING, AND MAINTENANCE PROCEDURES

The operating procedures for the plant reviewed refer to details of placing the system in operation during plant cooldown, removing the system from operation for plant startup, and operating the RHR purification bypass loop.

Before specific operating instructions are given in detail, some general precautions are outlined. Preclusion of a water hammer due to a cold water injection into a hot environment is addressed in these as shown by the excerpt (taken from the operating instructions) below:

> During the RCS heatup and cooldown with the valves open to the solid RCS, restarting of reactor coolant pumps - if all the pumps are stopped - can result in a sharp pressure surge. While all pumps are stopped. a quantity of cold seal injection water will accumulate in the pump volume and, upon starting a pump, will be heated in the steam generator causing a pressure surge. To preclude this problem during cooldown, at least one reactor coolant pump shall be kept running until the RCS temperature as indicated by TR-612 or TR-613 is < 160 F.

To minimize the possibility of Event 1 (see section on water hammer experience) occurring while placing the system in operation during plant cooldown, the following instructions are given in the operating procedures:

> Ensure that the low pressure letdown line is filled and vented as follows:
>
> 1. Connect a vent bottle rig at the vent line just upstream of HCV-128 in the letdown heat exchanger valve gallery.
>
> 2. Crack open MO-1363A or MO-1363B, RHR to L.P. letdown valve(s).
>
> 3. Vent the low pressure letdown line to the vent bottle rig.
>
> 4. AFTER venting is completed and vent valves closed, fully OPEN MO-1363A and/or MO-1363B.

It would be useful if these instructions are repeated or referred to in the section addressing the operation of the RHR purification bypass loop in the plant operating instructions. With regard to water hammer due to valve actuation, instructions call for the slow opening of the RHR heat exchanger flow control and bypass valves. Almost all the other valves in the system are lined up with the RHR pumps off. Hence water hammer due to fast valve actuation should not be a concern in the RHR system at the plant reviewed if the operating procedures are followed.

The periodic operating testing procedures for RHR system deal with In Service Testing (IST) of the RHR pumps and the pump discharge check valves. These tests are required to be performed quarterly and they involving starting a RHR pump against closed valves such that the pump operates in the recirculation mode. The opening of the pump discharge check valve is inferred if the pump operates satisfactorily ("part stroke" test for the check valve). It appears that the check valves are not tested full stroke in these IST program. It should be noted that as per (5) tilting disc check valves are generally less leak tight than swing check valves. Most of the check valves in the RHR system are tilting disc check valves (see Table 8-1 in the section on component data). In addition to the IST procedures, there are other periodic operating testing procedures and periodic engineering testing procedures that test for leakage, verify valves positions, exercise valves and monitor component degradation by comparing measured parameters against reference values. Stroke times are also determined for applicable valves in the testing program. As per plant operators, these times were mainly determined under no flow conditions in the past. However, more recently, emphasis is being placed on determining them under flow conditions. The results so far indicate that, in general, these times are not significantly different from those under flow conditions. However, the plant operators indicated that in some instances they have observed torque adequacy problems in closing against a pressure difference across valves.

Discussions with the plant personnel did not indicate any major maintenance problems with any of the RHR system components. They indicated that the RHR heat exchanger flow and bypass valves have been leaking and control of the cooldown rate is made more difficult because of this.

STRENGTHS AND WEAKNESSES FOR WATER HAMMER PREVENTION

Strengths

In general the main strength of the RHR system design and layout is that all the sources and sinks of water are placed at a high enough elevation that the system is not prone to line voiding and collapse situations. Also, the operating instructions call for the slow opening of the RHR heat exchanger flow control and bypass valves. Almost all the other valves in the system are lined up with the RHR pumps off. Hence water hammer due to fast valve actuation should not be a concern in the RHR system at this plant if the operating procedures are followed.

After Event 1 (see section on water hammer experience) occurred, the hardware and procedural changes made to the system discussed in the previous sections make the recurrence of such an event unlikely.

Weaknesses

The instructions that are designed to prevent the recurrence of Event 1 are given in one section of the operating procedures. It would be useful if these instructions are repeated or referred to in other sections that address the start of flow in the low pressure letdown line, e.g., the operation of the RHR purification bypass loop.

Discussions with plant operators indicated that they have had problems with RHR heat exchanger flow control and bypass valves HCV-606, HCV-607 and HCV-618, respectively. These valves leak and the operators have to adjust the CCW flow on the RHR shell side to control the RHR heat exchanger cooling rate. These three valves are butterfly valves, and if their duty requires heavily throttling, they may not be the preferred type. The use of globe valves is likely to be a better choice for this service.

REFERENCES

1. NUREG-0927 Revision 1, Evaluation of Water Hammer Occurrence in Nuclear Power Plants, 1984.

2. NUREG/CR-2781 QUAD-1-82-018 EFF-2203, Evaluation of Water Hammer Events in Light Water Reactor Plants, 1982.

3. NUREG/CR-2059 EGG-CAAD-5629, Compilation of Data Concerning Known and Suspected Water Hammer Events in Nuclear Power Plants, 1982.

4. Van Duyne, D. A., Yow, W. and Sabin, J. W., "Water Hammer Prevention, Mitigation, and Accommodation, Task 2 - Root Cause Analysis for Plant Water Hammer Experience." EPRI RP-2856-3, Task 2 Report, December 1989.

5. EPRI's Final report for project PR-2233-20, "Application Guidelines for Check Valves in Nuclear Power Plants," September 1987.

Table 8-1

RHR VALVES DATA

Valve	Designation	Size/Type	Measured Stroke Time (s)		Max. Flow Velocity (ft/s)
			Open	Close	
Miniflow Control	FCV-610	2" Globe Motor	8	6	56
Miniflow Control	FCV-611	2" Globe Motor	8	7	56
To CVCS	MO-1363	2" Globe Motor			
Hot Leg Suction	MO-8700 A/B	14" Gate Motor	16	16	9
Hot Leg Suction	MO-8701 A/B	14" Gate Motor		108	9
Hot Leg Suction	MO-8702 A/B	14" Gate Motor		106	9
Hot Leg Injection	MO-8703 A/B	12" Gate Motor	106	105	13
Loop Cross Tie	MO-8716 A/B	8" Gate Motor	9	8	30
To CCP/SIP Suction	MO-8804 A/B	8" Gate Motor	9	8	30
To Cold Legs Injection	MO-8809 A/B	8" Gate Motor	10	9	30
From Recirc. Sump	MO-8811 A/B	14" Gate Motor	16	16	9
RWST to RHR Pump	MO-8812 A/B	14" Gate Motor	15	18	9
Pump Discharge	MO-8730 A/B	8" Check Tilting Disc			30
Hot Leg Injection	MO-8736 A/B	8" Check Tilting Disc			15
Cold Leg	MO-8818 A,B,C,D	6" Check Tilting Disc			26
Cold Leg Injection	MO-8948 A,B,C,D	10" Check Tilting Disc			10
Hot Leg Injection	MO-8949 A,B,C,D	6" Check Tilting Disc			26
Suction from RWST	8948	14" Check Swing			17
RHR HX Bypass	HCV-618	8" Butterfly Air			
RHR HX Control	HCV-606	8" Butterfly Air	17	10	
RHR HX Control	HCV-607	8" Butterfly Air	24	14	
To Sampling System	HCV-1782	3/4" Butterfly Air			
To Sampling System	HCV-1783	3/4" Butterfly Air			
RHR HX Inlet	8724 A/B	8" Gate Manual			
RHR HX Bypass	8726 A/B	8" Gate Manual			
Pump Discharge	8728 A/B	8" Gate Manual			
RHR to RWST	8735	8" Gate Manual			
RHR to CVCS	8743 A/B	2" Globe Manual			
Hot Leg No. 4	PSV-8707	3" Pressure Relief			
Hot Leg Discharge	PSV-9808	3/4" Pressure Relief			
Cold Leg Injection	PSV-8856 A/B	2" Pressure Relief			

Table 8-2

RHR PUMP DATA*

Number	2 pumps
Type	Vertical, centrifugal
No. of Stages	1
Full Load rpm	1775
Horsepower	400
Shutoff Head	454 ft
Design Pressure	600 psig
Design Temperature	400 °F
Design Flow	3000 gpm
Design Head	375 ft
Max. Flow Rate	4500 gpm
Head at Max. Flow Rate	330 ft
NPSH at Max. Flow Rate	16 ft

* See Figure 8-5 for Pump Characteristic Curve

Table 8-3

RHR HEAT EXCHANGER DATA

	Shell Side	Tube Side
Design Temperature	200 °F	400°F
Design Pressure	150 psig	600 psig
Fluid Circulated	Component Cooling Water	Reactor Coolant
Design Flow Rate	2.475×10^6 lb/hr	1.85×10^6 lb/hr
Design Inlet Temp.	107.1°F	137°F
Design Outlet Temp.	118.5°F	122.3°F
Pressure Loss at Design Flow	20 psi	10 psi
Fouling Factor	0.0005	0.0003

Number of Heat Exchangers	2
Heat Exchanger Duty	28×10^6 Btu/hr
Heat Exchanger type	Shell and Tube, Vertical

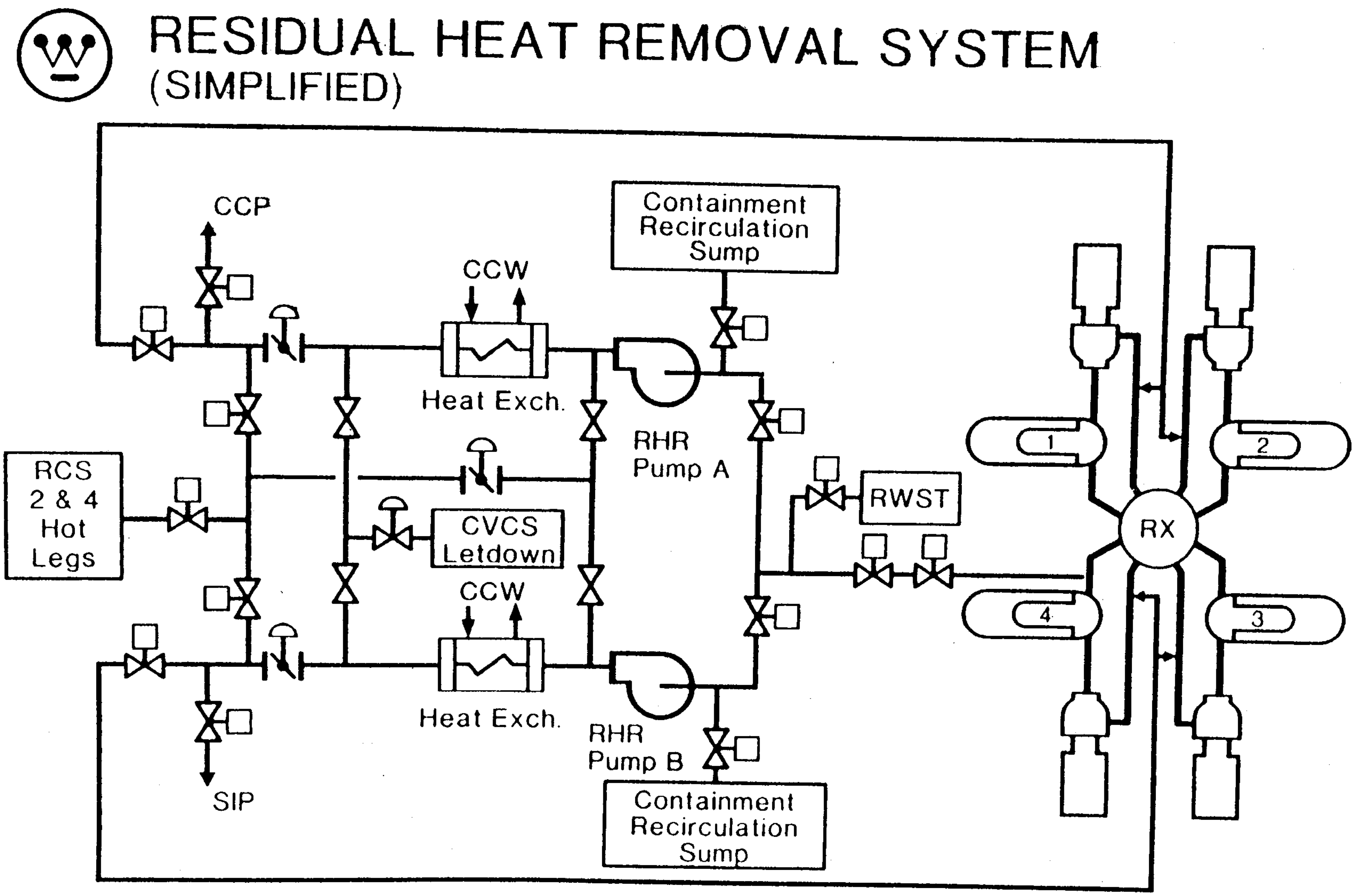


Figure 8-1. Simplified Schematic Diagram of the RHR System

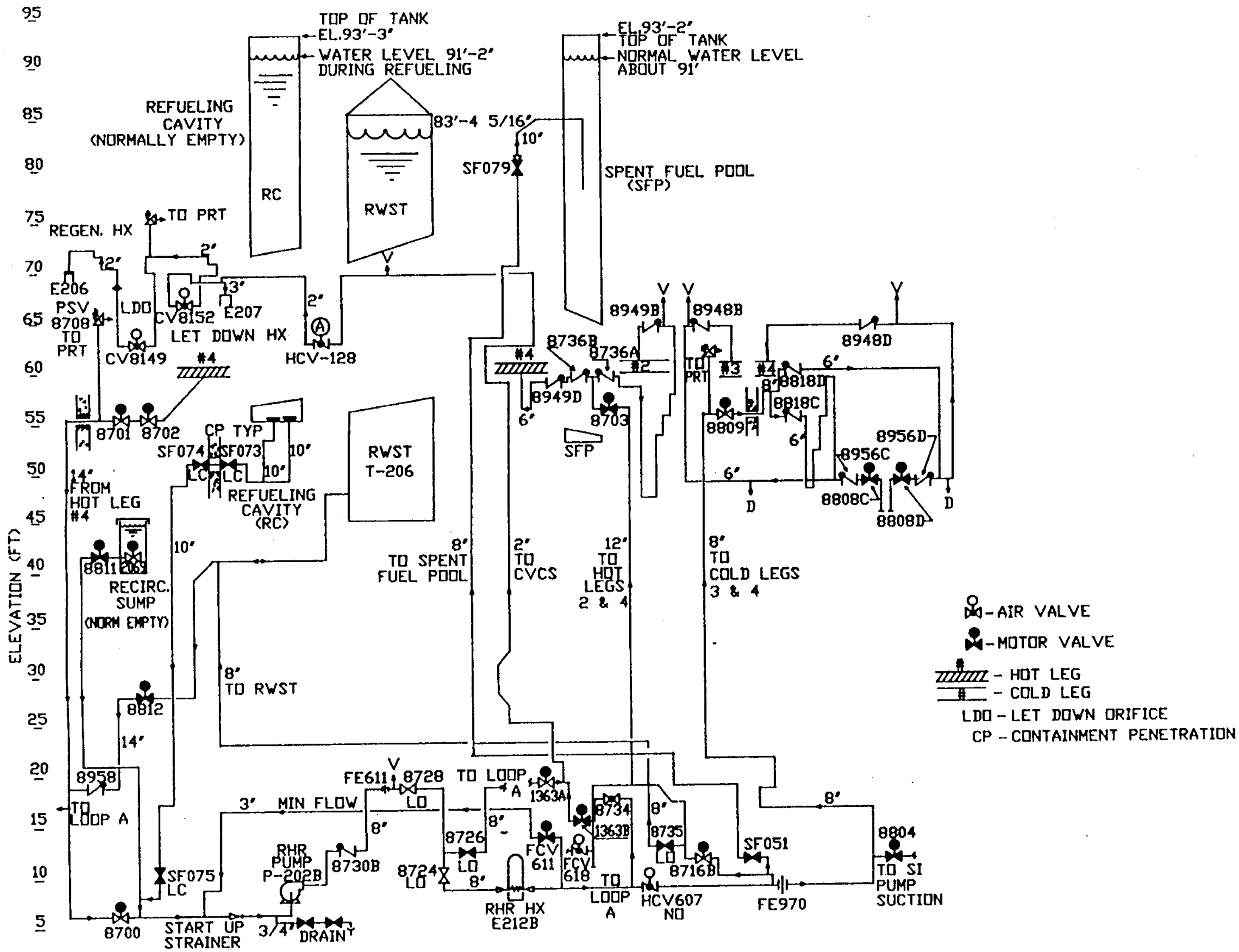


Figure 8-2. Elevation Diagram of the RHR "B" Loop Showing Plant Cooldown Mode Valve Lineup

RESIDUAL HEAT REMOVAL SYSTEM (STARTUP)

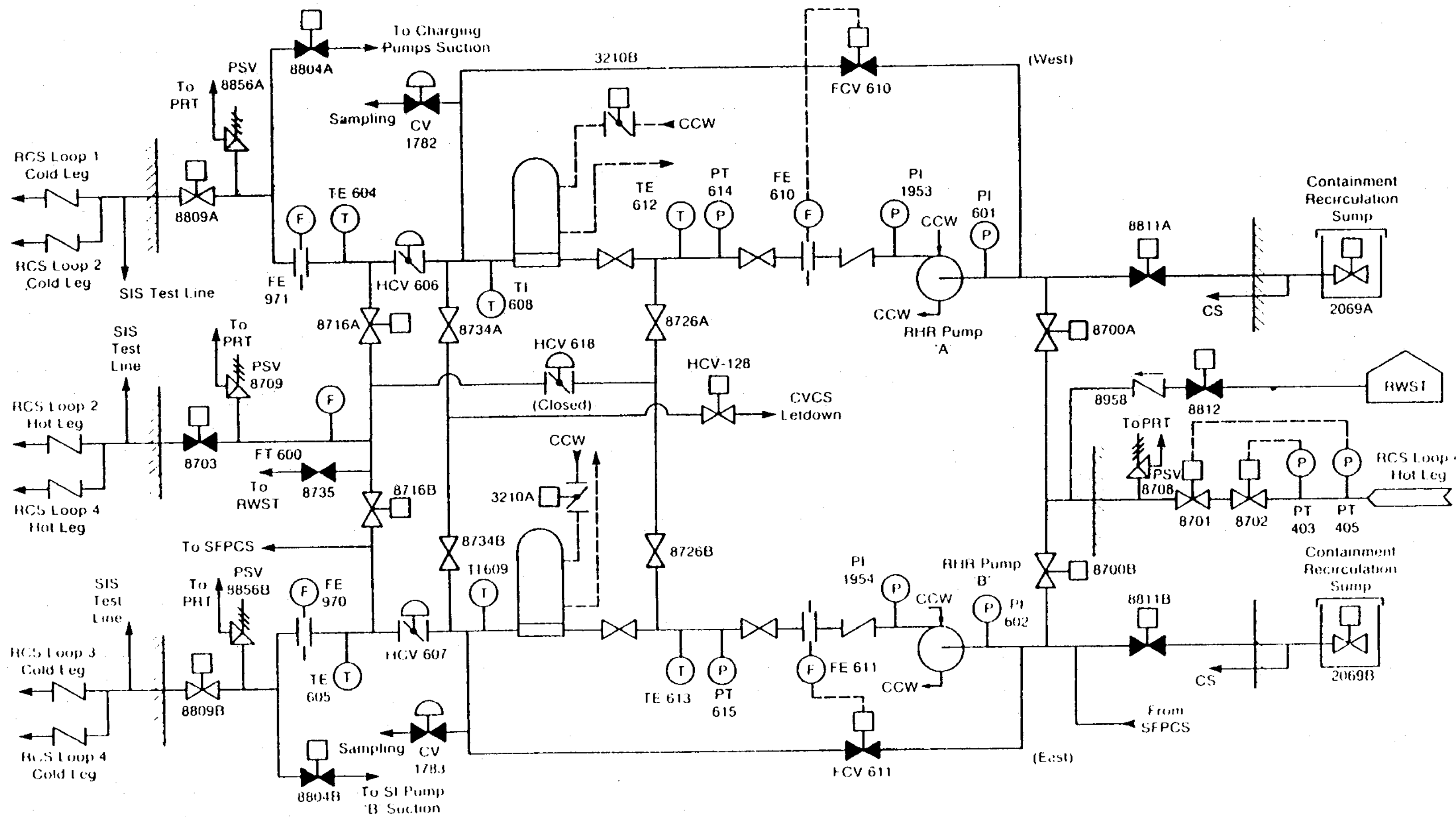


Figure 8-3. RHR System Lineup for Startup Mode

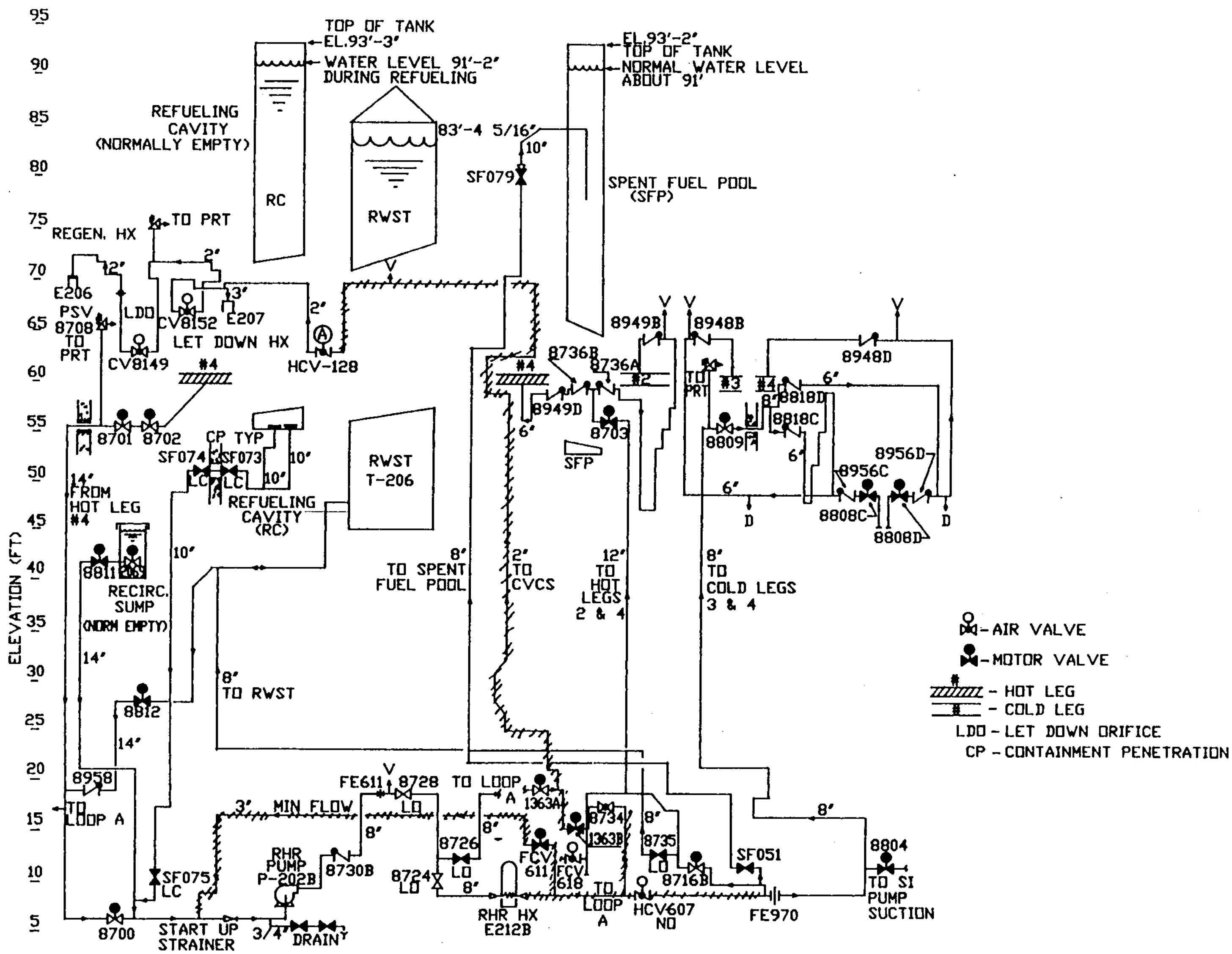


Figure 8-4. RHR System Elevation Diagram Showing Support Damage Area

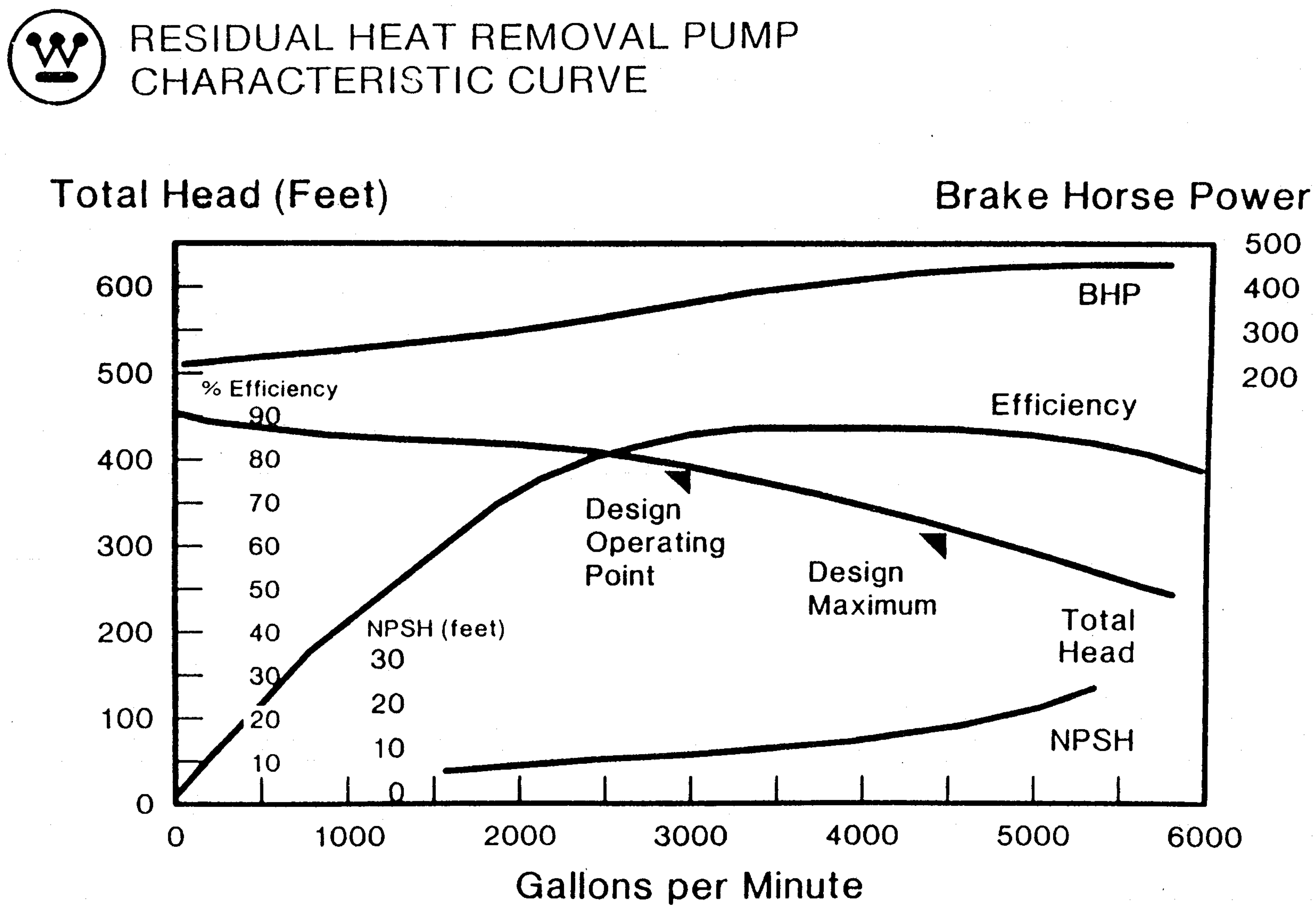


Figure 8-5. RHR Pump Characteristic Curve

Section 9

CORE SPRAY SYSTEM IN A BWR

SYSTEM FUNCTION

The core spray (CS) system, in conjunction with the low pressure coolant injection (LPCI) system, the feedwater coolant injection system and the automatic depressurization system (ADS), maintains the fuel peak clad temperature below acceptable limits for postulated reactor coolant line breaks, up to and including a design basis accident.

The core spray system provides protection to the core for a break in the reactor coolant system when the normal feedwater pumps, the control rod drive pump, and the feedwater coolant injection system are unable to maintain pressure vessel water level.

The CS system will supply cooling water, once the reactor pressure is reduced to about 300 psig. For intermediate breaks the automatic pressure relief system may be used to accelerate depressurization to enable CS actuation.

SYSTEM CONFIGURATION, MODES OF OPERATION AND COMPONENT DATA

Configuration

The core spray system is comprised of two physically and electrically separated loops. Each core spray loop contains a main pump and motor, valves, interconnecting piping and piping to the reactor pressure vessel. Figure 9-1 shows a simplified diagram for the CS system.

Inside of the reactor vessel, each core spray pipe is connected to a peripheral sparger above the core.

Accident signals start the system automatically. Manual start capability is also provided.

Figure 9-2 shows the elevation diagram of the CS for a plant in which water hammer events occurrences are discussed in the subsequent sections. Note that the horizontal distances in the figure are not to scale. Figure 9-3 shows the piping inside containment. The sparger inside the reactor vessel is shown schematically in the same figure. Loop B is shown in the figure, while it is noted that loop A is slightly different.

A full-flow 6-in. test line allows water to be circulated to the suppression pool for system testing during normal operation.

One testable air-operated check valve CS-6 and one motor operated valve CS-5 in each loop isolate the CS system from the reactor coolant boundary during normal plant operation.

The system is also provided with a keep-full system and vents to assure that the pump discharge line is always full (see Figure 9-2).

Core Spray System Operating Modes

Automatic and Manual Operation

The core spray systems are automatically initiated upon receipt of a Low-Low water level signal and low reactor pressure in the reactor vessel; or high drywell pressure. They can also be manually activated from the control room.

Upon receipt of any initiation signal and with normal auxiliary power available, both core spray pumps will start immediately (no delay). The pumps operate through the minimum flow bypass which discharges back to the suppression pool during the period when the injection valves are closed.

With pump motor bus power available, the injection valve will receive a signal to open in the presence of a LOCA signal after reactor pressure has decreased below a preset value. The LOCA signal also sends an "open" signal to the normally open suppression pool suction valve and a "close" signal to the normally-closed test line valve.

When a core spray pump starts, increasing pressure in the pump discharge line trips pressure switches which provide a permissive signal to the automatic pressure relief system (APR). The APR system, in turn, will operate to depressurize the reactor and permit the core spray system to inject water in an emergency, if high pressure coolant injection systems are unable to maintain adequate water level.

Testing

Operation of core spray system can be done manually from the Control Room for testing during or after normal power generation operation.

The ability of the core spray pump to start and deliver rated flow to the vessel can be demonstrated by utilizing the full flow test line in each loop. Water is pumped from and returns to the suppression pool.

The injection valve in each loop (CS-5) can be cycled if the upstream block valve (CS-4) has been closed previously (see Figure 9-2).

By following procedures, all relays in the system can be individually tested.

Interfaces with Other Systems

a) *Nuclear Boiler System*: The nuclear boiler system instrumentation provides the Low-Low reactor water level signal as well as the low reactor pressure interlock signals to activate the Core Spray System.

b) *LPCI/Containment Cooling System*: The Low Pressure Coolant Injection (LPCI)/containment cooling system's high drywell pressure trips provide another core spray autostart signal. The suppression pool return piping of the LPCI/containment cooling system provides a return point for core spray test line flow.

c) *Containment System*: The containment system provides the suppression pool water source for core spray pumps.

d) *Electrical Distribution System*: The core spray pumps, valves, and control system receives power from buses served by onsite, offsite, and battery sources.

e) *Turbine Building Secondary Closed Cooling Water System*: The Turbine Building secondary closed cooling water system provides cooling water to environmentally cool the core spray pump motors via area fan coolers.

f) *Condensate Storage Transfer System*: Connections to condensate system provide a source of pressurized water to maintain the core spray discharge lines full.

The pump suction connection to the condensate storage tank provides clean water pump testing discharge into the reactor vessel.

g) *Automatic Pressure Relief System*: The automatic pressure relief system depressurizes the reactor to allow the core spray system to inject water to the core.

h) *Reactor Building Floor Drain System*: Core spray piping pressure relief valves discharge to open floor drain of the Reactor Building floor drain system.

<u>Control Logic</u>

The control system is arranged to provide two independent and electrically separate control and power circuits for operation of two independent core spray loops.

Low-Low water level and high drywell pressure are each detected by four independent level and pressure switches connected in a one-out-of-two taken twice logic array. These same devices also initiate starting of the diesel generator and the gas turbine if loss of ac power has not already started them.

Filling, Venting, and Draining

A 2-in. keep full line (Figure 9-2) provides makeup water from the condensate storage tank to the 12-in. line downstream of the check valve CS-3 at approximate elevation of 10 ft.

Originally, MW-79 which was normally closed with valves MW-77 and MW-133 on the 3/4-in. line was modulated (see Figure 9-3). However, plant operation now uses the line up shown in Figure 9-3 with the valve MW-79 locked open.

The keep full line maintains a pressure of 130 psig into the system upstream of the injection valve CS-5 under plant normal operating conditions. It is noted that the keep full pump is non-safety powered. Also, note the vents at the high points of the system shown in Figure 9-2.

Cross Connect Between Loops

No direct tie exists between the two loops.

Component Data

Table 9-1 gives major data for the main valves in the CS system. Table 9-2 lists the CS pump data. Figure 9-4 shows the pump characteristics.

WATER HAMMER EXPERIENCE

In the 1970s a significant number of water hammer events were reported in LWR power plants. References (1) through (3) report on water hammer incidents reported since the early 1970s.

Each event was analyzed in the Task 2 Root Cause Report (4) to determine the areas of each system which are prone to water hammer, the specific water hammer mechanism, and root cause. The remedial actions taken by the utility to preclude future occurrence of a similar water hammer were described. Appendices A and B of (4) presented the BWR and PWR utility water hammer databases and Appendix C therein listed the utility plant codes used. Areas prone to water hammer were identified in typical schematics of each system discussed.

Three categories of severe water hammer were experienced.

- Startup of pump in voided line due to leaky pump check valve and/or inadequate filling system.

- Steam condensation induced water hammer upon pump start with steam leaking past CS injection valves.

- Severe cavitation vibrations in test line.

Three of the water hammer events that have occurred at the plant described in this section are briefly discussed below:

WATER HAMMER EVENT 1: PUMP STARTUP RESULTING IN RELIEF VALVE LIFT

Event Description

No observations for sequences during the event itself are available. The event is stipulated from post occurrence discoveries of the event. Prior to the occurrence the plant was operating at steady state power level of 95 percent. The core spray pump discharge relief valve was found leaking after it lifted during performance of a core spray pump operability surveillance which was successfully completed. The relief valve lifted due to the surge associated with the pump start.

When the relief valve was disassembled, small particles had become entrapped in the clearance between the valve disc and guide (and hence did not allow the valve to completely reseat).

The relief valve set pressure was 375 psig and it was concluded that the set pressure was relatively low, recognizing that the pump shutoff head is 360 psig.

Mechanism Responsible for the Event

This event did not involve a severe water hammer. The relief valve lifted because of the small set pressure. The event does not involve any of the severe water hammer mechanisms.

Analysis of Root Causes

The pressure waves associated with initial pump start, though small, were large enough to lift the relief valve because of the low set pressure. The event does not represent a significant water hammer.

Water Hammer Root Causes

Mild water hammer pressure waves associated with pump startup.

Corrective Measures Taken

By increasing the set pressure of the relief valve the problem was avoided.

WATER HAMMER EVENT 2: PUMP STARTUP WITH A VOIDED LINE

Event Description

No observations are available pertaining to sequences during the event, Damage was only discovered after the event. During refueling outage, inspections identified numerous deficiencies associated with the CS piping support systems. Evaluations indicated that original designs were inadequate to handle dynamic loads due to normal transients. Over a period of time, piping supports deteriorated.

Figure 9-2 has been marked to show areas where support damage was noted.

It is believed that some drainage of the line took place prior to pump startup in the test mode.

Mechanisms Responsible for the Event

Void formation can occur due to leakage at lower elevations in the CS pump check valve CS-3 (Figure 9-2) or other valves. The resulting void collapse transient upon pump start would be of the Mechanism 7 type.

Analysis of Root Causes

Through postulation of suspected void formation, calculating the resulting water hammer dynamic forces and comparing the predicted pipe displacements and stresses to the observed damages, the suspected mechanism was asserted. This is demonstrated through simple calculations given below.

From Figure 9-2, one notes that the injection valve CS-5 is at about 53 ft above the normal water level in the suppression pool. If the keep full is not operable then several possibilities giving rise to void formation exist. These are:

- Due to the finite test valve CS-21 closure time, if the pump is tripped before the valve is closed some drainage could occur resulting in a void forming at the high elevations upstream of the injection valve CS-5. As a result, in subsequent testing of the pump, a void would be encountered.

- Due to leakage through the check valve CS-3 or the test valve CS-21, a void could form at the high elevations upstream of the injection valve CS-5.

Depending on the leak size and duration prior to pump start in the testing mode, the void size will increase and potentially could encompass all piping sections above an approximate elevation of (32 + 30) ft. The 32 ft value is the water level in the suppression pool and the 30 ft value corresponds to the head corresponding to vapor pressure of the cold water normally in the system. This section has been designated by E-E in Figure 9-2.

If the pump is started with a void in the system, the system initially has small resistance and if one takes the runout flow rate of 6000 gpm, then the water may be rising in the voided line at a velocity as high as 25 ft/s in 10-in. pipe.

The Joukowsky equation (9-1), can be used to calculate the pressure rise due to the impact of this water when it hits the closed injection valve CS-4.

$$p = \rho \ a \ \Delta V \tag{9-1}$$

where

p = the pressure surge

ΔV = the velocity change

ρ = the density of the fluid

a = the speed of a pressure wave propagation in the pipe.

Using ρ = 62.4 lb/ft^3 and a = 4500 ft/s, the stoppage of the 25 ft/s flow velocity, yields:

$$p = 1500 \ lb/in^2$$

For a 10-in. pipe, this amounts to a dynamic force of about 118 kips.

The above calculation shows that a significantly large force could occur. It is noted that if the normal flow is used instead of the pump runout flow, still a force of the order of 80 kips would be calculated. Because of the fact that this event occurred several years ago, and as noted above it was only discovered through inspections during refueling outage, it is not possible to pin the extent of the void that prevailed prior to the pump startup.

It should also be noted that if the void is small, then it would collapse while the pump is starting. In such a case the lower driving head will give lower impact velocity of the filling water.

Referring to the system elevation diagram of Figure 9-2, though the horizontal distances are not drawn to scale one concludes that voiding up to the point designated E-E could occur easily in the absence of an effective keep full system.

Water Hammer Root Causes

Pump start in a voided line (Mechanism 7).

Corrective Measures Taken

By adding more and larger supports, the system's capability to withstand water hammer was improved.

WATER HAMMER EVENT 3: PUMP STARTUP WITH STEAM IN THE LINE

Event Description

Prior to occurrence, the plant was operating at steady power level of 100 percent.

No details on any observations during the event are available. Only information describing what was noted when the damage was discovered was available. After inspection of pipe supports on the CS subsystem A injection piping, several pipe supports were found damaged. Also, the two CS subsystem admission valves revealed the motor-to-valve operator bolts were loose.

The occurrence is attributed to water hammer that occurred during routine core spray pump operability surveillance. The water hammer was caused by steam bubble collapse in the piping due to seat leakage past the core spray injection valve and the core spray check valve.

Figure 9-2 shows portions of the system with observed pipe support damage.

Mechanisms Responsible for the Event

Due to leakage of hot water past the injection valve to the upstream side, a steam void forms. When the pump starts, we may again encounter Mechanism 7 or, if substantial condensation takes place, Mechanism 1 or 2 may be encountered. It may not be possible to pin point which mechanism among the aforementioned ones occurred during the event because important information is lacking. This is discussed further in the analysis of the root causes.

Analysis of Root Causes

With reference to Figure 9-2, if the check valve CS-6 and the injection valve CS-5 leak, and with an inadequate keep full system, this will result in the formation of a steam void at the high region of the piping upstream of the injection valve.

Depending on the leak size, the hot water passing beyond the injection valve will overcome the keep full pressure. Because the event occurred several years ago, it was not possible to obtain many details. It is believed that the keep full pressure at the time was about 30 psig. The hot water would flash and potentially a void of steam would be present. At equilibrium, the pressure of this steam void is most likely to be that of the keep full system, in this case approximately 45 psia. When the pump starts, the pump would encounter relatively small resistance. With a run-out discharge for the pump of 6000 gpm, the accelerated water column could reach a velocity as high as 25 ft/s.

However, in this event leakage occurs from the high pressure side, i.e. from downstream of the valve CS-5 in Figure 9-2. The size of the void and where the void will be located is difficult to establish. For a small leak rate, it is most likely that the steam void would extend in the top portion of the horizontal segment directly upstream of the injection valve CS-5. The larger the leak, the likelihood of the void moving upstream on the horizontal run gets bigger. As for the equilibrium size of the steam void, it would be governed by the flow rate of the leak, and the heat loss from the steam to the pipe wall to the cold water. A quasi-steady condition would prevail. Figure 9-5 shows sketches depicting a number of possible situations.

It is of interest to focus on the prevailing conditions of the water close to the upstream of the void at this quasi-steady condition.

When the pump starts, the water will be accelerated very rapidly due to the low pipe wall resistance. If the water that is in contact with the steam void is at relatively high temperature, the event will be primarily a water column separation event with Mechanism 7. The severity of such a transient would be less than that of Event 1 for two reasons: a) the void size in this event is believed to be smaller, and b) since the pressure in the steam void is higher, the water column acceleration occurs under a small pressure differential. Under this situation, the void collapse would occur due to the impact of the two water columns on the sides of the void; thus equation 9-2 would be utilized rather than equation 9-1:

$$p = \frac{1}{2} \rho a \Delta V \qquad (9\text{-}2)$$

Thus, even using the pump runout discharge, the surge force would amount to about 59 kips.

On the other hand if the water/steam interface of the void becomes relatively cold due to the pump start, then rapid condensation will occur. Potentially, the void pressure would drop to the saturation temperature of the water reaching the void. In this case, either Mechanism 2 would be encountered if the void was in the horizontal pipe, and Mechanism 3 would occur if the steam void was in the vertical line. Again, the bounding force for either of these two mechanisms will be still given by equation 9-2, i.e., at 59 kips. This force probably exceeds the capacity of the supports causing their damage.

Water Hammer Root Causes

Leakage past the injection valve and failure to detect this leakage before the pump was started represent the two main aspects of the root causes of this event.

Corrective Measures Taken

The pipe supports in question were modified and repaired. Special type screws were installed in the admission valve motor-to-operator bolt holes to prevent vibration induced loosening.

The spray check valve was to be replaced and the core spray injection valve was to be reworked and fitted with test connections so that seat integrity could be monitored. The keep full was to be modified using one of the schemes shown on Figures 9-6 or 9-7.

SYSTEM EVALUATION

Normal Transients

The system frequently experiences

- pump start with full system

- pump start with full system, then opening test valve CS-21 in 8 to 8.65 s.

- with full system and under no flow condition (i.e. after closing CS-4), the CS injection valve CS-5 opens and closes in 11 s.

- with full flow through test line, valve CS-21 closes in about 8 s.

- pump trip with initial full flow.

It is observed (from Table 9-1) that the velocity in the test line is significantly high which may lead to large loads associated with test valve CS-21 closure.

In this plant, the piping supports for the core spray system were not sized based on a specific transient that served as a design basis for hydraulic transient loads, but the loads were inferred from damage occurring in events such as those described under Events 1 and 2 in the Water Hammer Experiences section. The portions of the piping that have encountered support damage are marked in Figure 9-2.

Severe Transients

The possibility of water hammer involving Mechanisms 1, 5, and 6 is small due to the absence of steam in the system in the context of the requirements for these mechanisms.

Severe transients involving flow of cold water into a steam void (Mechanism 2) or water column separation (Mechanism 7) could occur under:

a) There is potential for a severe transient (Mechanism 2) should the reactor vessel water level decrease followed by subsequent rise of the water level causing trapped steam in the horizontal sections of the lines leading to the core spray nozzles. Upon opening of the injection valve CS-5, cold water could come in contact with the trapped steam, resulting in possible rapid steam condensation induced water hammer. This transient is quite similar to the commonly known PWR feedwater steam generator water hammer (4). The potential for occurrence of this transient can be asserted through the examination of the durations of low water level and hence assessing void formation. Figure 9-8 shows some geometrical details of typical CS piping.

b) Steam Leakage Through Valves

With reference to Figure 9-2, potential for steam and void formation due to leakage past the check valve CS-6 and the injection valve CS-5 would give rise to a severe water hammer transient (Mechanism 2 or 7). Mechanism 2 would prevail if cold water gets in contact with the hot steam and the phenomenon encountered will involve simultaneous steam condensation together with movement of the slug due to the prevailing pressure differential across the water columns. On the other hand, if condensation does not occur, then the transient would be inertia governed and Mechanism 7 is encountered. Check valves are known to develop leaks. If the injection valve CS-5 does not leak, we will have possibly a small steam void on the downstream side of valve CS-5. Hence, when the injection valve CS-5 opens (upon the low probability occurrence of LOCA or during surveillance testing) a steam condensation induced water hammer occurrence is minimum.

If the injection valve CS-5 leaks, a potential for a large void forming upstream of valve CS-5 exists. Again the potential for excess steam condensation induced water hammer (Mechanism 2) or (Mechanism 7) water hammer upon pump startup would be large. By maintaining the pressure in the core spray system upstream of the injection valve at high pressure (130 psig), the severity of this transient is reduced.

It is observed that through use of temperature sensors, leakage beyond valves CS-6 and CS-5 can be detected in a more definitive manner.

c) Void Formation due to leakage in the lower elevations should CS pump check valve CS-3 (Figure 9-2) on other valves develop any leak, a potential for void forming at the high elevations does exist. This transient would be of the Mechanism 7 type. Through the keep full system, this potential is eliminated. With the 2-in. keep full system, and maintaining a pressure of 130 psig, leaks can be detected.

d) Possibility of occurrence of LOOP (Loss Of Off-Site Power) after LOCA (Loss Of Coolant Accident). Should a LOOP occur following a LOCA, the keep full system may not be capable of maintaining the system full following pump trip if substantial leakage occurs through check valve CS-3. Upon pump restart the potential for flow into a voided line may cause water hammer of the Mechanism 7 type. An additional precaution related to this problem would be to close CS-21 should the system be in test mode upon LOCA signals to avoid draining through that valve.

   It should be noted that this transient has a very low probability and may be beyond the licensing design basis of the plant.

e) Column rejoining in the CS sparger.

Prevention/Mitigation/Accommodation

From the discussions of above, one observes that the incidents encountered in the past are those under categories b and c.

Transients "a" and "d" above, may only occur upon a LOCA. The likelihood of occurrence of type "d" is relatively small. It is felt that type a can prevention may not be possible its and mitigation can be accomplished through a slow opening of the injection valve. For type "d" transients, recognizing the low probability of occurrence, the need of further evaluation for each plant should be addressed depending on the licensing commitments of the plant.

Drainage can be minimized by closing the test valve CS-21 automatically upon loss of power.

As for transients "b" and "c", some measures can be utilized:

- Prevent valve leakage through choice of appropriate type of valve, and proper maintenance.

- Adopt positive measures to detect leakage occurrence (temperature, pressure sensors). The schemes in Figure 9-8 and Figure 9-9 to be utilized to detect both void and steam leakage.

- Utilize an adequate keep full system.

Reference (6) reports on positive experiences reached through adoption of keep full system to prevent water hammer in core spray system in BWR plant. In addition to the above, pipe supports should be sufficiently large to at least withstand water hammer under normal transients.

REVIEW OF OPERATING, TESTING AND MAINTENANCE PROCEDURES

The operating procedures for the plant reviewed address:

- operations to fill CS loop A and B
- operations to initiate CS system
- operations to terminate CS system and operations to return it to standby status
- actions to be taken during system malfunctions.

The following precautions are included specifically for water hammer concerns:

- When a core spray keep fill line has been isolated, its core spray header must be vented (see locations of vents in Figure 9-2).

- Do not start a core spray pump for testing unless keep fill pressure is sensed.

The plant operation procedures do factor the lessons learned from incidents encountered on the plant and other plants. Discussions with one of the plant operators showed good awareness of water hammer potential when running the CS system.

Discussions with maintenance personnel at the plant reviewed, indicate that upon detection of leakage in the injection valve CS-5, the valve was relapped and re-installed. More recently valves CS-6 and CS-7 (Figure 9-2) have been replaced. Earlier on because of pipe material problems the core spray piping inside the drywell was replaced.

The motor operators on all of the CS system are being replaced to a limit torque operator type. It is observed that the air operator on the stop check valve CS-6 (Figure 9-2) is out of service.

The maintenance procedures do not show routine periodic inspections on the system valves and pumps. Inspections are covered under the inservice inspection program at the plant. However, should unusual observations be encountered during system operation and/or during outages, appropriate actions will be taken.

Attention is drawn to EPRI's "Application Guidelines for Check Valves in Nuclear Power Plants" (7) to recognize potential problems on the system's check valves and hence address them for best reliability.

	Testing Frequency
Pump	Monthly
Injection Valve	Monthly

STRENGTHS AND WEAKNESSES FOR WATER HAMMER PREVENTION

Strengths

The adoption of the keep full system and keeping the system under pressure aids in the prevention of Mechanism 7 and mitigates Mechanisms 2 and 3.

Weaknesses

A temperature sensor or an alarm system could aid in detection of steam formation and hence be a more effective prevention measure.

Figures 9-6 and 9-7 give suggested schemes for the detection of steam leakage and void formation.

REFERENCES

1. NUREG-0927 Revision 1, Evaluation of Water Hammer Occurrence in Nuclear Power Plants, 1984.

2. NUREG/CR-2781 QUAD-1-82-018-2203, Evaluation of Water Hammer Events of Light Water Reactor Plants, 1982.

3. NUREG/CR-2059 EGG-CAAD-5629, Compilation of Data Concerning Known and Suspected Water Hammer Events in Nuclear Power Plants, 1982.

4. Van Duyne, D. A., Yow, W., and Sabin, J. W., "Water Hammer Prevention, Mitigation, and Accommodation, Task 2 - Root Cause Analysis for Plant WAter Hammer Experience," EPRI RP-2856-3, Task 2 Report, December 1989.

5. Safwat, H. H., "Steam Condensation Induced Water Hammer," International Association for Hydraulic Research Wroking Group on Hydraulic Transients with Water Column Separation, 8th International Round Table on Hydraulic Transients in Power Stations, September 14-17, 1987, Madeira, Portugal.

6. Waterhammer Eliminated During Reactor Testing, Electric Light & Power, Vol. 6, October 1987.

7. EPRI's Final Report for Project PR-2233-20, "Application Guidelines for Check Valves in Nuclear Power Plant," September 1987.

Table 9-1

VALVES DATA

					Stroke Time Seconds		Pipe Velocity[3]
Valve	Operator	Number	Type[2]	Size	Opening	Closing	ft/s
Injection Valve	M	CS-5A,B	G	10 in.	11	11	14.86
Suction Valve	M	CS-2A,B	G	12 in.	68	68	10.31
Relief Valve	M	CS-18A,B	P	2-1/2 in. x 4 in.			
Full Flow Test Valve	M	CS-21A,B	G	6 in.	8.0 (8.65)	8.3 (8.85)	41.25
Testable Check Valve	M	CS-6A,B	T	10 in.			14.86
Outboard Valve	M	CS-4A,B	G	10 in.	11	11	
Condensate Supply Valve	M	MW-91A,B	G	12 in.			
Check Valve CS-3	T						

1 M: motor A: air T: tilting disc check valve

2 G: gate Gl: globe P: poppet

3 Based on CS pump rated discharge 3600 gpm.

Table 9-2

PUMP DATA

Pump Impeller diameter	13-5/16inches
Full Operation Volume Flow Rate	3600gpm
Total Dynamic Head	618ft
Available NPSH (min)	30ft
Shutoff Head	680ft
Speed	3560rpm

Pump is vertical, single stage, double suction with inline suction and discharge nozzles.

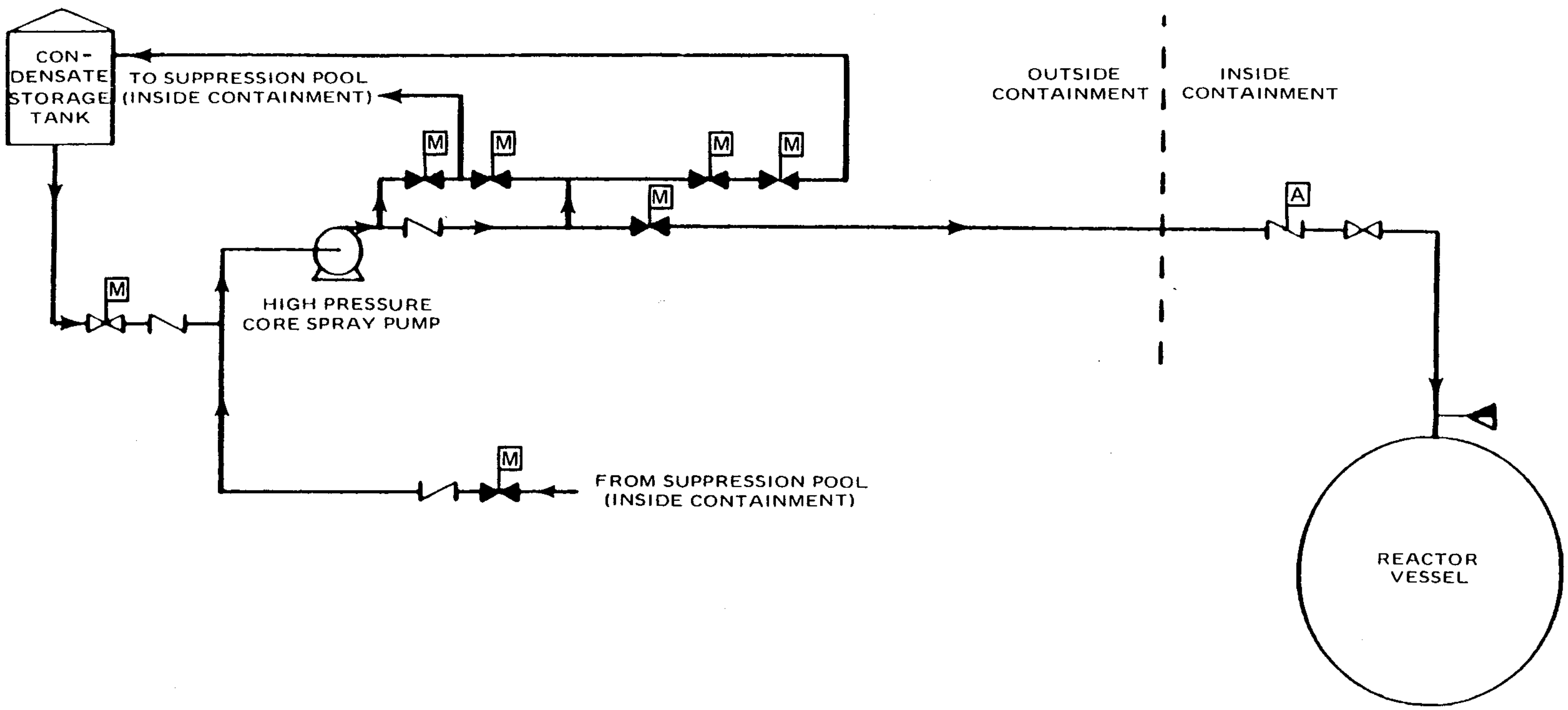


Figure 9-1. Schematic of a Typical Core Spray System

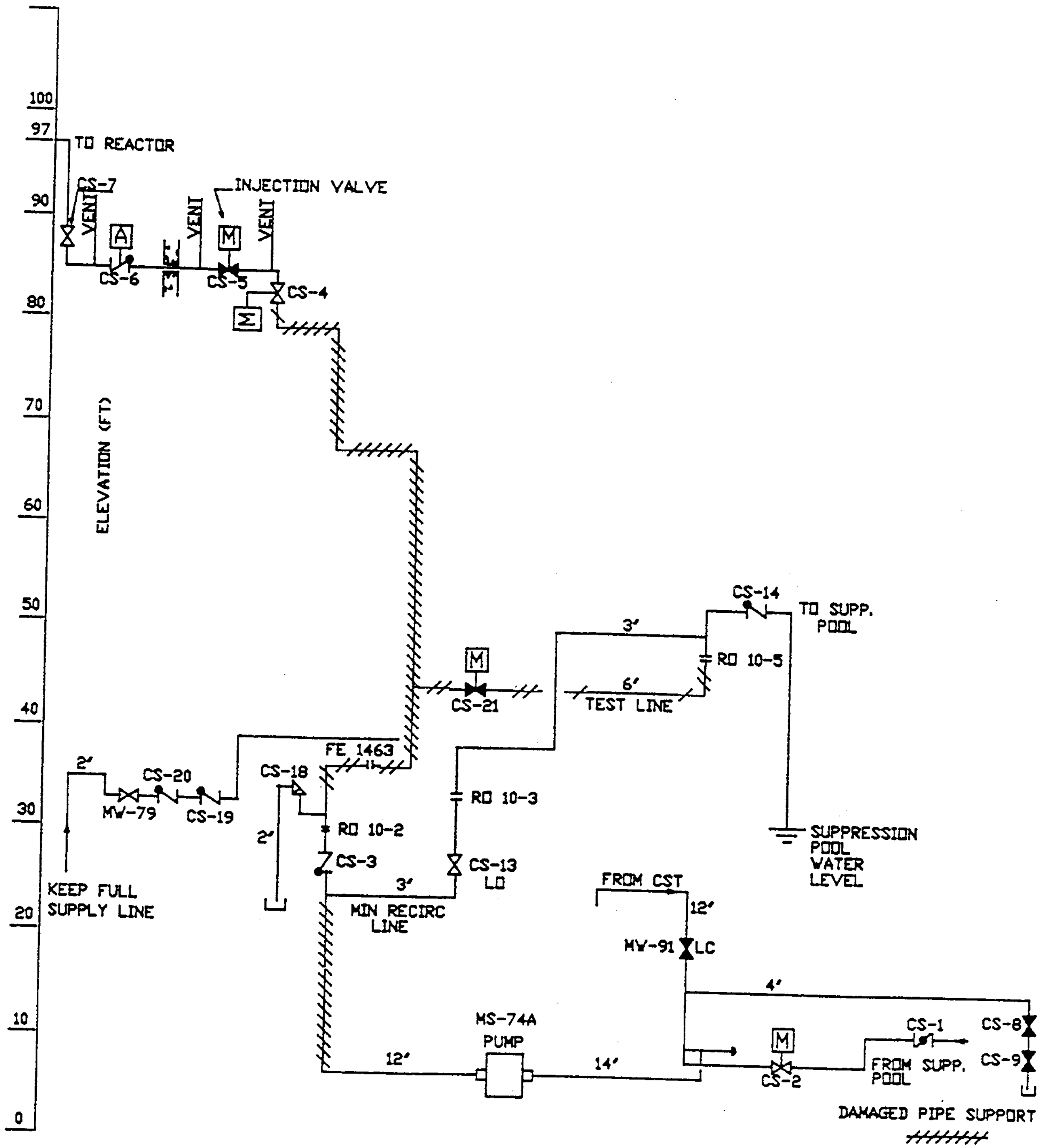


Figure 9-2. Elevation Diagram for Core Spray System

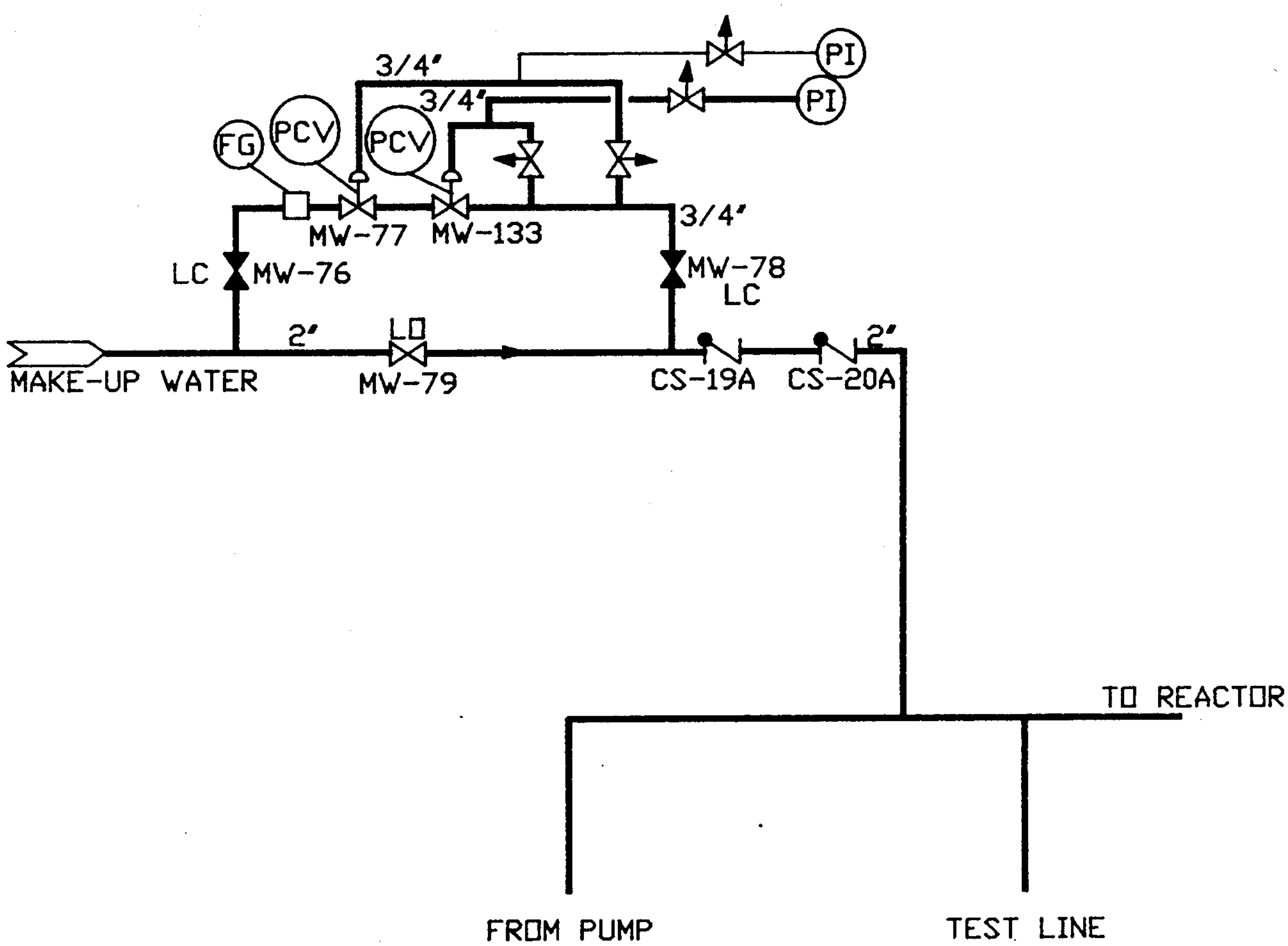


Figure 9-3. Schematic Showing Modulating Valves on the Keep-Full Line

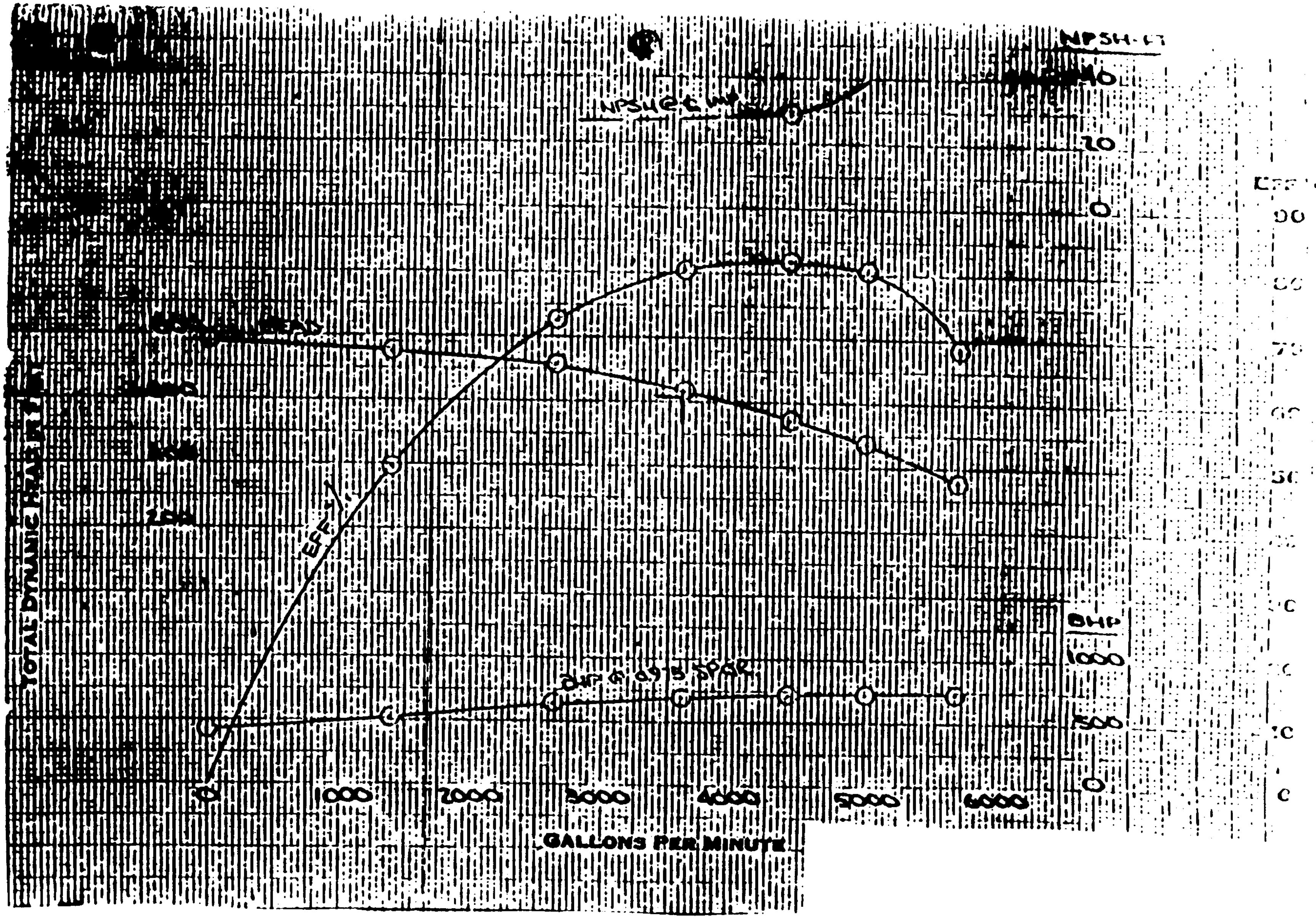


Figure 9-4. Pump Characteristics

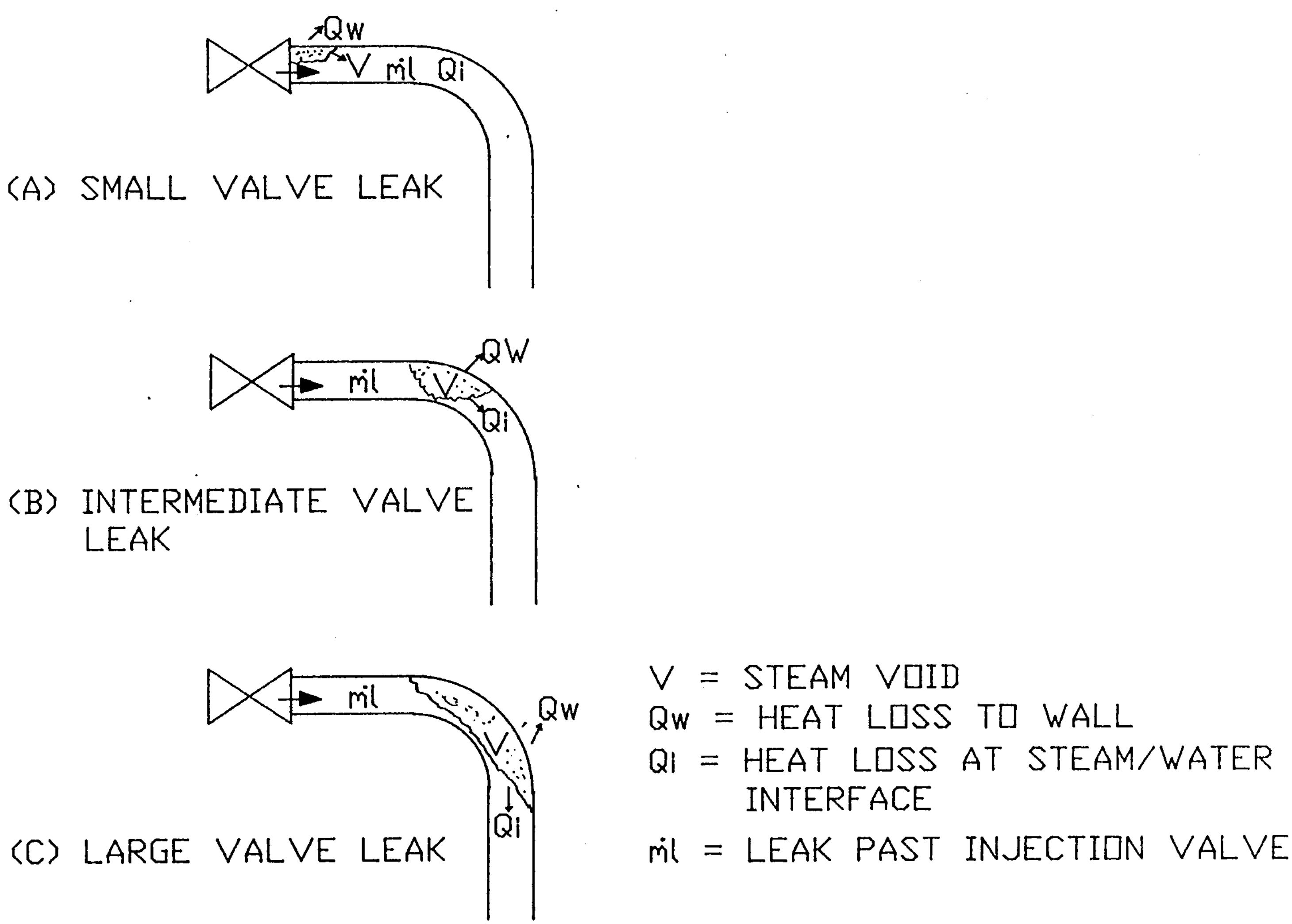
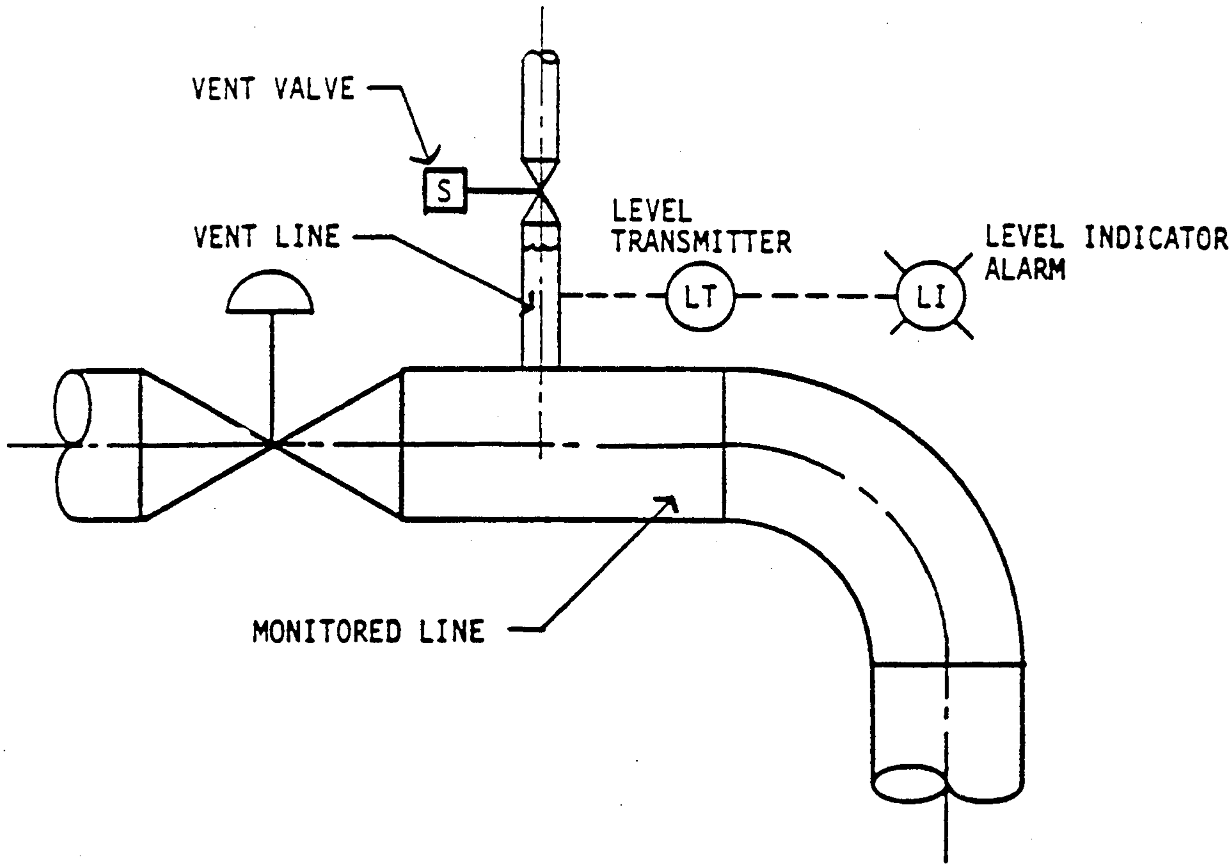
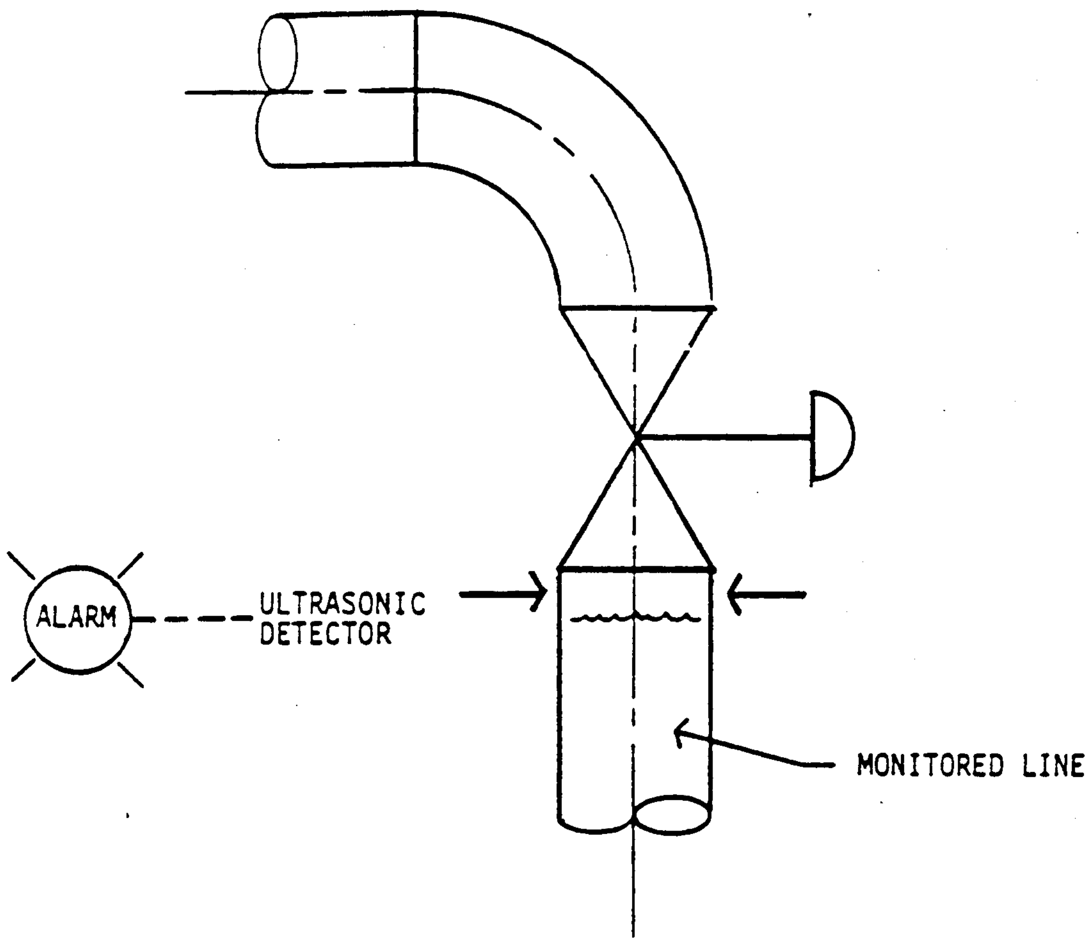


Figure 9-5. Schematics Showing Possible Void Formations



LEVEL TRANSMITTER IN VENT LINE DETECTS THE
INCIPIENCE OF VOIDING AND PROVIDES ALARM.

Figure 9-6. Scheme Number 1 for Detection of Steam Leakage and Void Formation into a Line



ULTRASONIC DETECTOR, DETECTS VOID IN
VERTICAL LINE AND PROVIDES ALARM.

Figure 9-7. Scheme Number 2 for Detection of Steam Leakage and Void Formation into a Line

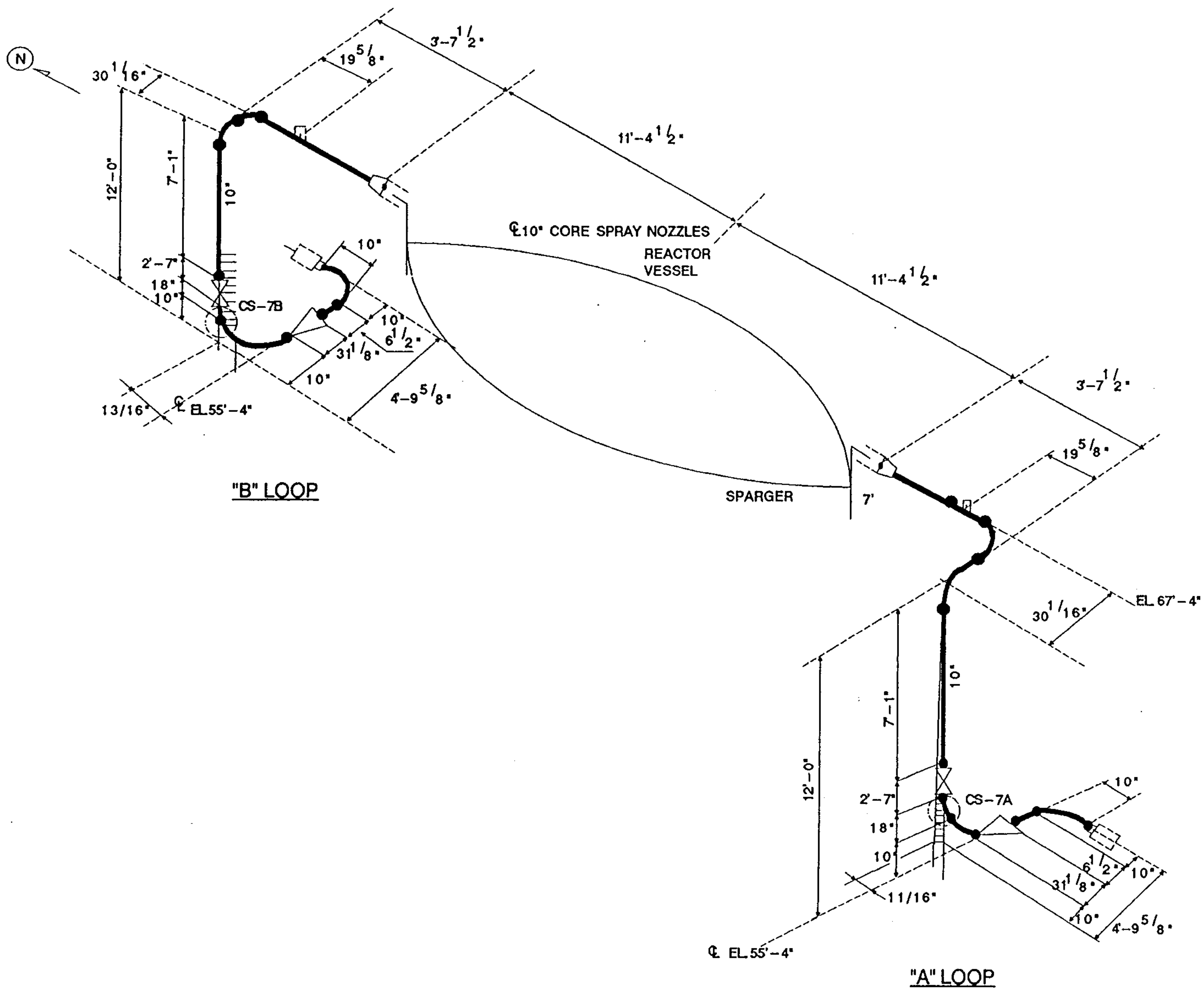


Figure 9-8. Details of Core Spray System Piping Inside Containment and at Entrance to the Reactor Pressure Vessel

Section 10

LOW PRESSURE COOLANT INJECTION/CONTAINMENT COOLING SYSTEM IN A BWR

SYSTEM FUNCTION

The low pressure coolant injection/containment cooling (LPCI) system, in conjunction with the core spray (CS) system, the feedwater coolant injection (FWCI) system and the automatic depressurization system (ADS), maintains the fuel peak clad temperature below rupture limits for all breaks up to and including a design basis accident.

Accident signals start the system automatically. Manual start capability is also provided.

After the initial core cooling operations, the LPCI system is used to cool the containment by passing suppression pool water through the heat exchangers and returning the water directly to the pool or indirectly via spray spargers in the drywell.

In addition to the injection and containment cooling modes, the LPCI system has a full flow test mode and a suppression pool spray mode.

The system has no power generation requirements.

SYSTEM CONFIGURATION, MODES OF OPERATION AND COMPONENT DATA

Configuration

The LPCI system is comprised of two physically and electrically separated loops. Each loop contains two main pumps and motors, a heat exchanger, valves, and interconnecting piping, including piping which connects to the discharge side of each recirculation loop.

Each loop takes water from the suppression pool and pumps water into the reactor via one of the two discharge lines which connect with the recirculation pump discharge lines. Figure 10-1 is a simplified system diagram.

Figure 10-2 is an elevation diagram for the LPCI system showing major valves, vents, drains, and line elevations. In this diagram the vertical elevations are shown to scale where as the horizontal ones are not.

LPCI System Operating Modes

Normal Operation

The torus cooling (not spray cooling) function of the system may be used to cool the suppression pool such that it is maintained at a temperature consistent with the plant technical specification. This is generally needed after main steam safety/relief valve testing.

Testing capability is provided in the design of the LPCI system piping, valving and controls. Stepwise operation of the system components can be done manually from the control room for testing during or after normal power generation. Full LPCI pump flow capability can be demonstrated by recirculating water to and from the suppression pool during normal plant operation. Similarly, all the electrical controls can be tested singularly or as a system except that the injection valve does not open during such testing.

Emergency Operation

LPCI Subsystem Automatic Operation

The LPCI subsystem is automatically initiated upon receipt of a low-low reactor water level signal combined with a low reactor pressure signal or upon receipt of a high drywell pressure signal.

A valid signal of either high drywell pressure or low-low water level alone will initiate start of both the standby gas turbine generator and diesel generator sources regardless of whether normal off-site power is available or not.

Either high drywell or low-low water level signals will also initiate loop selection logic which determines which recirculation loop has broken piping (if any). The logic is arranged so that LPCI injection will occur in loop B unless the recirculation sensors indicate that pressure in recirculation loop A is at least 1.0 psi greater than loop B (indicating failure of loop B). However, neither LPCI injection valve will be signalled open until vessel pressure has decreased enough such that the design pressure of the LPCI discharge piping is not exceeded (350 psi). Only one LPCI injection valve will be signalled open while the other is signalled closed by the loop selection logic.

In addition to initiating start of the LPCI pumps, the combination of reactor low level and reactor low pressure or high drywell pressure also signals closure of the suppression pool test return valves (normally closed) and containment spray valves (normally closed), starts the emergency service water pumps (normally stopped), and signals the containment cooling heat exchanger bypass valves open (normally open).

The system will remain in LPCI mode until action is taken by the plant operator to revert to the containment spray or containment cooling mode of operation.

Any pump autostart signal can be overridden by the plant operator at any time. Auto restart can occur only if the original signal is reset.

The following is an expected sequence of events after initiation of the LPCI system with normal power available:

(1) The system is automatically initiated even in the test mode by either +2 psig in the drywell or -48-in. reactor water level with less than 350 psig reactor pressure.

(2) The diesel generator and the gas turbine generator will start on either +2 psig in the drywell or -48-in. reactor water level. The diesel and gas turbine generators will not supply emergency buses if normal power is available.

(3) The torus spray valves, the drywell spray valves, and the test line isolation valves will all receive an "auto close" signal.

(4) The LPCI heat exchanger bypass valve will receive an "auto open" signal for 60 s.

(5) All four LPCI pumps will start and run on minimum recirculation flow until the LPCI loop selection logic selects a recirculation loop for injection.

(6) A signal is sent to the ESW pumps to secure them if running. Since the LPCI heat exchanger is bypassed in the injection mode, the ESW pumps are not necessary.

(7) The LPCI loop selection logic will determine the damaged loop and send a "close" signal to the recirculation system pump discharge valve. This will force all LPCI flow through the normal core inlet path. A "close" signal is also sent to the LPCI injection valves associated with the damaged recirculation loop as described previously. A five minute "open" signal is sent to the LPCI injection valves for the intact recirculation loop when reactor pressure drops to 350 psig.

(8) All four LPCI pumps are now pumping water into the reactor vessel through one set of LPCI injection valves to the unbroken recirculation loop. The pumps can be stopped by momentarily placing the control switch in the "stop" position.

In the event of a loss of normal off-site power, the initiation and loop selection are identical as above. Starting the LPCI pumps is done sequentially to avoid overloading the diesel generator.

Containment Spray and Suppression Pool Cooling

The containment cooling function (actuation of the drywell or suppression chamber sprays) can be performed with the system after the core is flooded which, for even the largest line break, is accomplished within a few minutes. Two of the LPCI pumps can then be shut down and two containment cooling emergency service water pumps will be started manually to provide cooling water to the heat exchangers. Suppression pool water can then be diverted to either of the two cooling modes: containment spray cooling or suppression chamber cooling.

The containment spray control logic will deactivate the containment spray system when containment pressure is below 5 psig. On low drywell pressure and the spray valves are signalled closed. The pool return valves have similar logic except that low drywell pressure does not cause automated closure of these valves.

Interfaces with Other Systems

a) Nuclear Boiler: The nuclear boiler system provides the low reactor level signal as well as reactor low pressure interlock signals.

b) Recirculation System: This system provides differential pressure switch signals which are used in the LPCI loop selection logic.

c) Containment System: The containment system provides the suppression pool water source for the LPCI pumps.

d) 4160V Electrical System: The LPCI and emergency service water pumps receive power on-site and off-site sources.

e) Turbine Building Secondary Cooling Water System: This system provides cooling water to environmentally cool the LPCI pump motors via area fan coolers.

f) Condensate Storage System: The CST is an alternate source of water to the LPCI pump suction water.

g) Core Spray System: The LPCI test return line provides a common pool penetration for the core spray full flow test line.

h) Shutdown Cooling System: The B loop LPCI injection line serves as the return line for the shutdown cooling system.

Control Logic

The containment cooling heat exchanger service water has instrumentation which controls the service water discharge valve position so that service water is maintained at a slightly higher pressure than the process water side.

All remote actuated valves, and drywell check and manual block valves have open or closed position indication in the control room so plant operators can verify valve status.

The LPCI/containment cooling system contains the drywell pressure instrumentation which initiates the automatic LOCA response and limits the containment spray function at low drywell pressures.

Each of the four pumps has suction and discharge pressure gauges and seal leakoff instrumentation. Each loop has flow transmitters and control room indication for main line flow, LPCI injection line flow and service water flow to the loop heat exchanger. It also has a high pressure alarm switch in the low pressure portion of the discharge piping.

Filling, Venting, and Draining

With reference to Figure 10-2, the system has a number of vents at high points and the system is maintained full through a keep-full system. This keep-full system maintains a pressure of 35 psig in the system and is supplied from the condensate storage tank.

Component Data

Component data for major valves in the system are tabulated on Table 10-1. Data for the pumps and heat exchangers are given in Tables 10-2 and 10-3, respectively. The pump characteristic curve is shown as Figure 10-3.

WATER HAMMER EXPERIENCE

In the 1970s a significant number of water hammer events were reported in LWR power plants. References (1) through (3) report on water hammer incidents reported since the early 1970s.

Each event was analyzed in the Task 2 Root Cause Report (4) to determine the areas of each system which are prone to water hammer, the specific water hammer mechanism, and root cause. The remedial actions taken by the utility to preclude future occurrence of a similar water hammer were described. Appendices A and B of (4) presented the BWR and PWR utility water hammer databases and Appendix C therein listed the utility plant codes used. Areas prone to water hammer were identified in typical schematics of each system discussed.

It has been found that the causes of water hammer in LPCI systems, in the order of significance, are:

- Flow into a voided line (Mechanism 7)
- Steam bubble collapse (Mechanism 3)

According to (1) through (4), the procedural and engineering factors contributing to the above causes are:

- A lack of awareness concerning the possibility of water hammer events, their causes and the potential damages
- A lack of information available to the operator concerning the conditions in the system, to allow him to take proper action
- Equipment malfunctions, including unintended use and maintenance- related failures of components
- Inadequate design consideration of potential water hammer

Two of the events that have occurred at the plant described in this section are briefly disussed below:

WATER HAMMER EVENT 1: PUMP STARTUP WITH A VOIDED LINE

Event Description

No observations are available on what happened during this event. The only information available are those related to damage that was discovered sometime after the event occurred. While investigating supports on the torus ring, it was observed that some of the hangers on the eighteen inch LPCI cross-tie line had been subjected to horizontal deflections which caused damage to the pipe support. An investigation determined that most likely the damage resulted from flow into a voided line which occurred during the early operational phases of the system. Referring to Figure 10-2, the elevation differences show the possibility for drainage through lower sections. The leakage through the pump discharge valve was suspected.

Mechanisms Responsible for the Event

Flow into a voided line (Mechanism 7).

Analysis of Root Causes

The piping sections where supports damage were observed are marked in Figure 10-2. When the event was discovered two possible causes were stipulated and investigated.

Under the first, it was assumed that a sudden injection of 260 psi water occurred into the crossover line which had been maintained (water solid) at 60 psi by the pressure regulating valve in the condensate system. For an 18-in. pipe this would correspond to force of approximately 50 kips.

Under the second scenario, sudden injection of 260 psia water occurred into the crossover line which had air at 14 psia in it. The analysis performed at the time estimated load of 212 kips for this scenario.

By comparing the calculated line deflections resulting from the two scenarios to those from the damage observed, it was concluded that the second scenario is the more likely one.

While all of the details surrounding the original evaluations are not available, it is not clear why air was assumed to exist under scenario 2. Also, the assumption of the sudden pressure rise to 260 psi is not clear but from the discussions of Event 1 of the core spray system, one can see the significant loads associated with water flow due to pump startup in a voided line. This will be discussed further in Event 2 for the LPCI system.

<u>Water Hammer Root Causes</u>

Pump start in a voided line (Mechanism 7).

<u>Corrective Measures</u>

The likelihood of recurrence of this event is small since the keep-full system is now in continuous operation. In addition, modifications to the supports were made to meet higher loads.

WATER HAMMER EVENT 2: PUMP STARTUP WITH A VOIDED LINE

<u>Event Description</u>

Under a newly incorporated Inservice Inspection program, the inspections identified numerous deficiencies in the LPCI piping support systems. Thus no details on sequences or observations noted during the event are available. Whether the observed damage was during one particular event or a number of events could not be confirmed either. The evaluation concluded that the supports had not been designed to handle the normal loads adequately.

<u>Mechanisms Responsible for the Event</u>

Pump startup in a voided line (Mechanism 7).

Analysis of Root Causes

As noted above, the observations available are post the occurrence and we do not have details on what consequences lead to the damage hence we are only left with postulations. The discussions that follow are parallel to those presented in the analysis of the second event in the core spray system. Since the support damage extended past the injection valve LP-10 (see Figure 10-2), one concludes that some leakage must have occurred through that valve. This is stipulated though the documentation of this event does not mention this as a fact. Referring to Figure 10-2, two situations could have occurred, both with valve LP-10 leaking and the keep-full system inoperational resulting in voiding of the piping at the high elevations.

i. If check valve LP-11 did not leak, then low pressure void will be formed.

ii. If check valve LP-11 was not tight, then hot water would leak beyond the valve and result into a steam void.

It is believed that situation i. was encountered rather than ii. The discussions hereafter will be limited to that situation. The reader interested in situation ii. is referred to the section discussing the root causes analysis of Event 2 of the core spray system.

Turning to situation i., a large void could develop when the system was in the standby condition (normally the case when the plant is running). The void would have been at a pressure of approximately -30 ft of water gauge. When the LPCI pump started, a high void filling velocity would be encountered.

If one assumes that because of the low resistance at this stage, the pump runout flow (from pump characteristics 6000 gpm) conditions exist, then a filling velocity as high as 25 ft/s in 10-in. line will result. Assuming a water density of 62.4 lb/ft^3 and a pressure wave speed equal to 4500 ft/s and using Joukowsky's law, yields a dynamic force of about 120 kips.

This force far exceeds the capabilities of the supports of the system. While one must recognize that the estimate of the 120 kips is quite conservative and allowing for friction, etc., would lower the estimated force. But even a force of 59 kips which would correspond to a filling velocity of 12.5 ft/s would have been excessive for the existing supports.

Water Hammer Root Causes

Pump startup in a voided line (Mechanism 7).

Corrective Measures

Modifications to the supports to meet higher loads. Design modifications and repairs were made.

SYSTEM EVALUATION

Normal Transients

Piping support design was not based on any particular transient. Original piping was "chart-hung" based on ANSI B31.1. No rigorous water hammer analysis was performed. Modifications to pipe supports were made following the events described earlier in this section. The portions of the piping that have encountered support damage are marked on Figure 10-2.

Upon actuation of the containment spray, flow into the empty spray header line is expected to cause some degree of water hammer. The small amount of piping downstream of the isolation valves and the large throttling at the motor operated glove valve (LP-15A or B) combine to create relatively slow filling of the header, thus reducing the force of the water hammer. This is an expected transient and the supports should be designed to handle it. A detailed evaluation for this transient was not performed as part of this review, and it is recommended that such evaluation be performed.

Severe Transients

The results of a review of the LPCI system for potential causes of severe water hammer are given below. The seven severe water hammer mechanisms given in

Section 2 have been found to be responsible for most of the severe water hammer events that have occurred in the past in commercial nuclear power plantrs. Hence the susceptibility to water hammer for the LPCI system will be evaluated for each of these mechanisms.

Water hammer Mechanism 1 (water cannon) is caused by the reflooding of the line that discharges steam into a water pool. Because steam is not initially present in the system and the process conditions are such that steam flow into the suppression pool from the LPCI system is not expected to occur, Mechanism 1 is not considered credible as a cause of water hammer.

The only source that can introduce steam into the system is leakage of high energy fluid from the LPCI/reactor recirculation line connection. For water hammer Mechanism 2 (steam water counter flow in a horizontal pipe) to occur, there must again be a steam source and flow rate of cold water in a steam/water counter flow rate must be within a range that has been established in task 5 to potentially cause water hammer (see Figure 10-4 taken from the Assessment Guidelines). The LPCI injection flow is greater than 15,000 gpm (as per station operating procedures) which is much larger than the flow required to keep the pipe full and preclude a water hammer by Mechanism 2 even if a steam/water counter flow could be initially established.

The potential for steam bubble collapse type of water hammer (Mechanism 3) exists at the high pressure/low pressure interface (injection line). Valve leakage allows the high pressure, high temperature fluid into the low pressure water lines, forming steam bubbles in the lines. Check valves are known to develop leaks. If the injection valve (LP-10A or B) is tight, the likelihood of void formation in the portion of the line between the injection valve and the drywell check valve (LP-11A or B) will be small. Hence, when the injection valve opens, a steam condensation induced water hammer is not likely to occur (Mechanism 2 for Loop B or 3 for Loop A). If the injection valve leaks, potential exists for void formation and, hence steam condensation induced water hammer occurrence upon pump start. The severity of this transient would be reduced by maintaining the keep-full line at a high pressure as in the core spray system in this plant. The lower pressure LPCI keep-full system pressure will mitigate the transient, but to a lesser extent.

Water hammer Mechanism 4 (hot water discharge to low pressure line)has been observed inheater drain systems where hot saturated liquid discharges into a low pressure system following cold liquid. Such conditions do not exist for the LPCI system and hence this mechanism is not considered credible.

Water hammer Mechanism 5 (steam propelled water slug) potentially exists in systems containing steam. This is not the case in the LPCI system is not susceptible to this mechanism.

Transients due to rapid valve opening or closing events because of actuator failure or rapid closure od a stuck opened check valve have been catagorized as Mechanism 6. Regular maintenance of all the valves and their actuators will prevent water hammer from this mechanism. This is specially true for the check valves in the system. There are several check valves in the LPCI system. Valves 1-LP-9A and 1-LP-9B are stop check valves and these should be maintained well to prevent their sticking open or closed.

Flow into a voided line is the most common cause of water hammer reported for LPCI systems as reported in (2) (Mechanism 7). These type of events have been considerably reduced due to the installation of keep-full system. However, some concerns are noted below.

The first potential cause of a severe transient is the lack of a method to detect line voids. Plant operating procedures (discussed later) require a minimum keep-full line pressure of 35 psig before start of LPCI pumps for test. However, no method exists to detect line voids (Mechanism 7). Pump restart immediately following a trip could occur before the keep-full system can repressurize the LPCI lines (Mechanism 7).

For a loss of offsite power following LOCA with automatic restart of the LPCI pumps, the only path for drain down of the lines is back leakage through the pump discharge check valve. It is not expected that the line could drain down sufficiently to be of concern. However, a LOCA concurrent with a loss of offsite power that occurs while the system is in the test mode or pool cooling mode is a different situation. The piping would drain down to the suppression pool through the open flow path with water hammer resulting when the pumps restart.

Since the LPCI system is used only infrequently for testing and pool cooling, this is probably not a concern. The need to evaluate such a transient depends on the licensing commitment of the plant. However, other plants with higher system usage factors may need to examine this situation more closely.

The keep-full line is supplied from the condensate storage tank (CST) that is usually a non-safety related system. We find no indication of a safety related backup to the keep-full system. Therefore, in case of loss of offsite power drainage could occur resulting in water column separation with possibility of occurrence of Mechanism 7 upon pump restart.

Also, the keep-full line is a single input to the loop crosstie. Because the loop crosstie does not have double isolation valves, whenever the loops are isolated from each other, Loop A is also isolated from the keep-full system.

REVIEW OF OPERATING, TESTING AND MAINTENANCE PROCEDURES

The station operating procedures for the LPCI system were reviewed and these were found to address the following aspects of system operation:

a) Placing the LPCI/Containment Cooling System in standby readiness.

b) Operational sequence of LPCI/Containment Spray system with:
   - Normal power available
   - Power from turbine/diesel generator in the absence of normal power.

c) Shifting LPCI pump suction from suppression pool to condensate storage tank (CST).

d) Supplying LPCI pump suction from the Emergency Service Water (ESW) header.

From the review of the operating procedures it is seen that attention has been given to the prevention of water hammer in the LPCI system operation. For example, the following precaution are quoted from these procedures:

If the LPCI system keepfill regulators have been isolated, both 'A' and 'B' LPCI systems must be filled and vented with the keepfill system in service and the system cross-tie valve 1-LP-8A open.

To prevent piping and hanger deamage due to water hammer do not start LPCI pumps for testing unless keepfill pressure is a minimum of 35 psig at PCV outlet. A pressure reading of about 45 psig would indicate that the primary PCV has failed and that the back up PCV is controlling keepfill pressure.

With the exception of testing, maintain 1-LP-8A open at all times to ensure an injection flowpath for all four LPCI pumps.

All of the above three precautions address the prevention of water hammer due to the creation and filling of a voided line. The first precaution requires the system filling using the keepfill system when the regulators are isolated. The second deals with ensuring the adequacy of the keep-full system during test mode and the third prevents the isolation of the keep-full system for one of the two loops (loop A) by the requirement to keep the cross-tie valve open.

The procedures require confirmation that the LPCI pump suction valves are open prior to pump start to prevent column separation and rejoining in the suction lines.

While addressing the shifting of the suction from suppression pool to the CST the operator is cautioned not to start the LPCI pump before the suction valves realignment is complete.

Detailed testing procedures were not available and hence were not reviewed.

The maintenance procedures for the LPCI pumps do stress the importance of filling the pumps with water after maintenance requiring pump isolation. This includes the venting of the pump to release entrapped air or vapor in the pump casing. Suction valves are required to be open before starting the pumps and suction and discharge pressure gauges must be monitored to determine any loss of suction resulting in column separation. The valve maintenance procedures were not available and hence were not reviewed. However, the valves should be regularly inspected to detect any possible leakage. Check valves should receive particular attention.

STRENGTHS AND WEAKNESSES FOR WATER HAMMER PREVENTION

Strengths

Use of keep full system (see Figure 10-2)

Plant operating procedures require that the keep-full line be at a minimum pressure before starting a pump for test.

Weaknesses

The first potential cause of a severe transient is the lack of a method to detect line voids. Plant operating procedures require a minimum keep-full line pressure of 35 psig before start of LPCI pumps for test. However, no method exists to detect line voids (Mechanism 7). Use of devices such as those shown in Figure 10-5 and 10-6 would be helpful.

Pump restart immediately following a trip could occur before the keepfill system can repressurize the LPCI lines (Mechanism 7) and fill any voids completely.

The keep-full line is supplied from the condensate storage tank (CST) that is usually a non-safety related system. Therefore, no keep-full system is available following loss of offsite power (Mechanism 7). True safety related keep-full should be powered by batteries, etc., which prevent drainage during loss of offsite power until diesels energizing the relevant buses.

Also, the keep-full line is a single input to the loop crosstie because the loop crosstie does not have double isolation valves. Whenever the loops are isolated from each other, Loop A is also isolated from the keep-full system. Probability of this happening is low as per discussions with plant operators because operating procedures require cross-tie valve to be open before pump start.

REFERENCES

1. NUREG 0927 Revision 1, Evaluation of Water Hammer Occurrence in Nuclear Power Plants, 1984.

2. NUREG/CR-2781 QUAD-1-82-018 EFF-2203, Evaluation of Water Hammer Events in Light Water Reactor Plants, 1982.

3. NUREG/CR-2059 EGG-CAAD-5629, Compilation of Data Concerning Known and Suspected Water Hammer Events in Nuclear Power Plants, 1982.

4. Van Duyne, D. A., Yow, W., and Sabin, J. W., "Water Hammer Prevention, Mitigation, and Accommodation, Task 2 - Root Cause Analysis for Plant Water Hammer Experience," EPRI RP-2856-3, Task 2 Report, December 1989.

5. Van Duyne, D. A., Rooney, J. W, and Sabin, J. W., "Water Hammer Prevention, Mitigation, and Accommodation. Task 5 - Water Hammer Prevention, Diagnostic and Assessment Guidelines." EPRI RP-2856-3, Task 5 Report, October 1990, draft report.

Table 10-1

LPCI MOTOR OPERATED VALVES DATA

Valve	Designation	Type	Stroke Time Opening	Stroke Time Closing
Pool Suction Block Valve	LP-2A,B,C,D	Gate	85 s	85 s
Heat Exchanger Bypass Valve	LP-7A,B	Gate	18 s	18 s
Cross-tie Valve	LP-8A,B	Gate		
Outboard Stop Check Valve	LP-9A,B	Stop Check	18 s	18 s
Injection Valve	LP-10A,B	Gate	18 s	18 s
Pool Spray Block Valve	LP-13A,B	Gate	37 s	37 s
Pool Spray Throttle Valve	LP-14A,B	Globe	17 s	17 s
Containment Spray Throttle Valve	LP-15A,B	Globe	18 s	18 s
Containment Spray Block Valve	LP-16A,B	Gate	23 s	23 s
Minimum Flow Valve	LP-26A,B	Gate		
Pool Return Block Valve	LP-43A,B	Gate		17 s
Pool Return Throttle Valve	LP-44A,B	Globe		19 s

Table 10-2

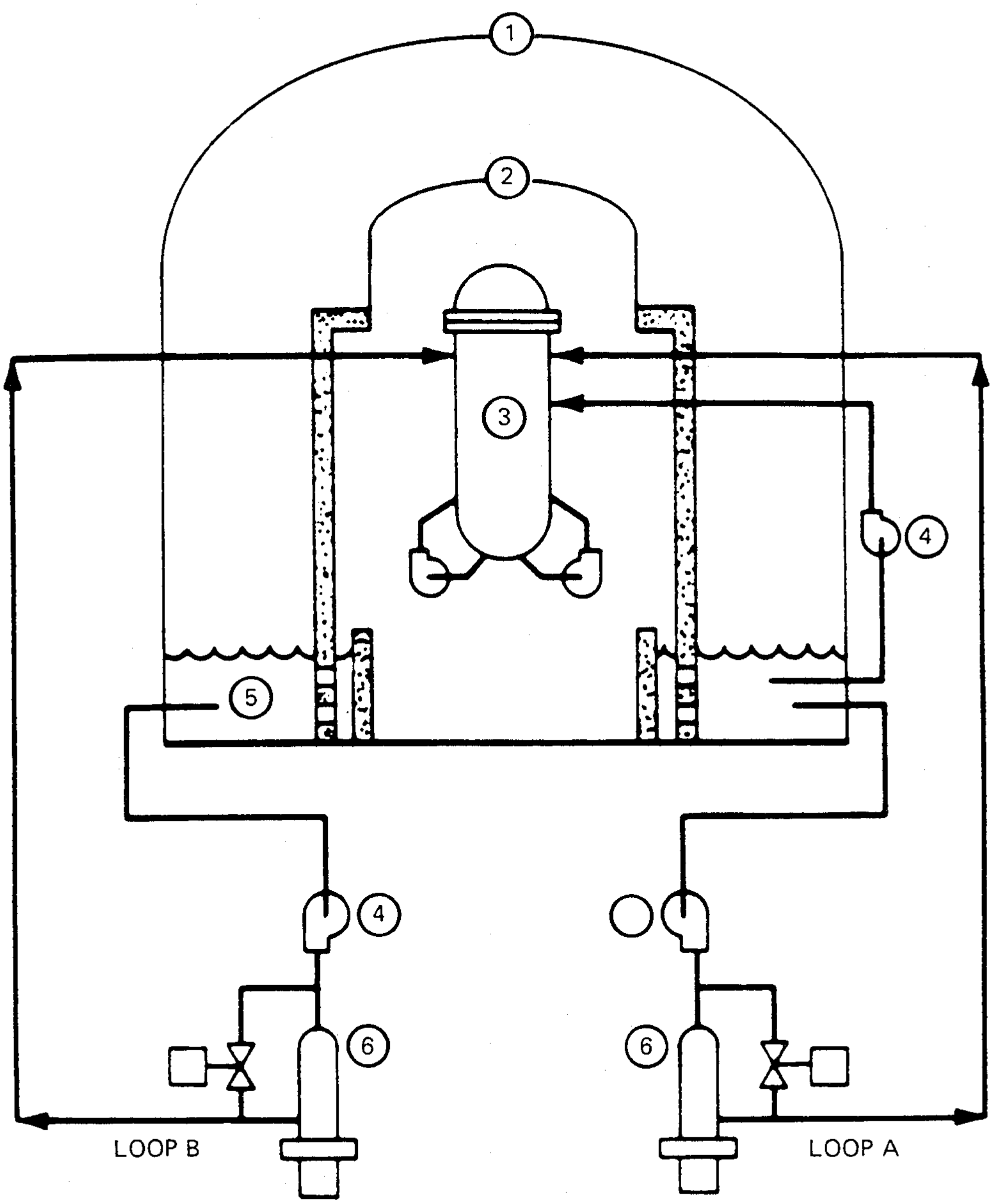
LPCI PUMP DATA

Number	4 pumps
Type	Vertical, In-line
No. of Stages	1
Speed	3600 rpm
Shutoff Head	620 ft
Rated Flow	4500 gpm
Rated Head	240 ft
Min. Flow Requirement	250 gpm

Table 10-3

LPCI HEAT EXCHANGER DATA

	Shell Side	Tube Side
Design Temperature	205 °F	205 °F
Design Pressure	300 psig	300 psig
Fluid Circulated	Demineralized Water	Emergency Service Water
Flow Rate	5000 gpm	5000 gpm
Inlet Temperature	165 °F	75 °F
Outlet Temperature	149 °F	91 °F
Pressure Drop	10 psi	10 psi
Fouling Factor	0.0005	0.0005
Heat Exchanger Duty	40,000,000 BTU/hr	



In the plant where the events discussed in this section took place the pumps and heat exchangers inside containment.

1. CONTAINMENT
2. DRYWELL
3. RPV
4. SYSTEM PUMP
5. SUPPRESSION POOL
6. HEAT EXCHANGERS

Figure 10-1. Simplified System Diagram

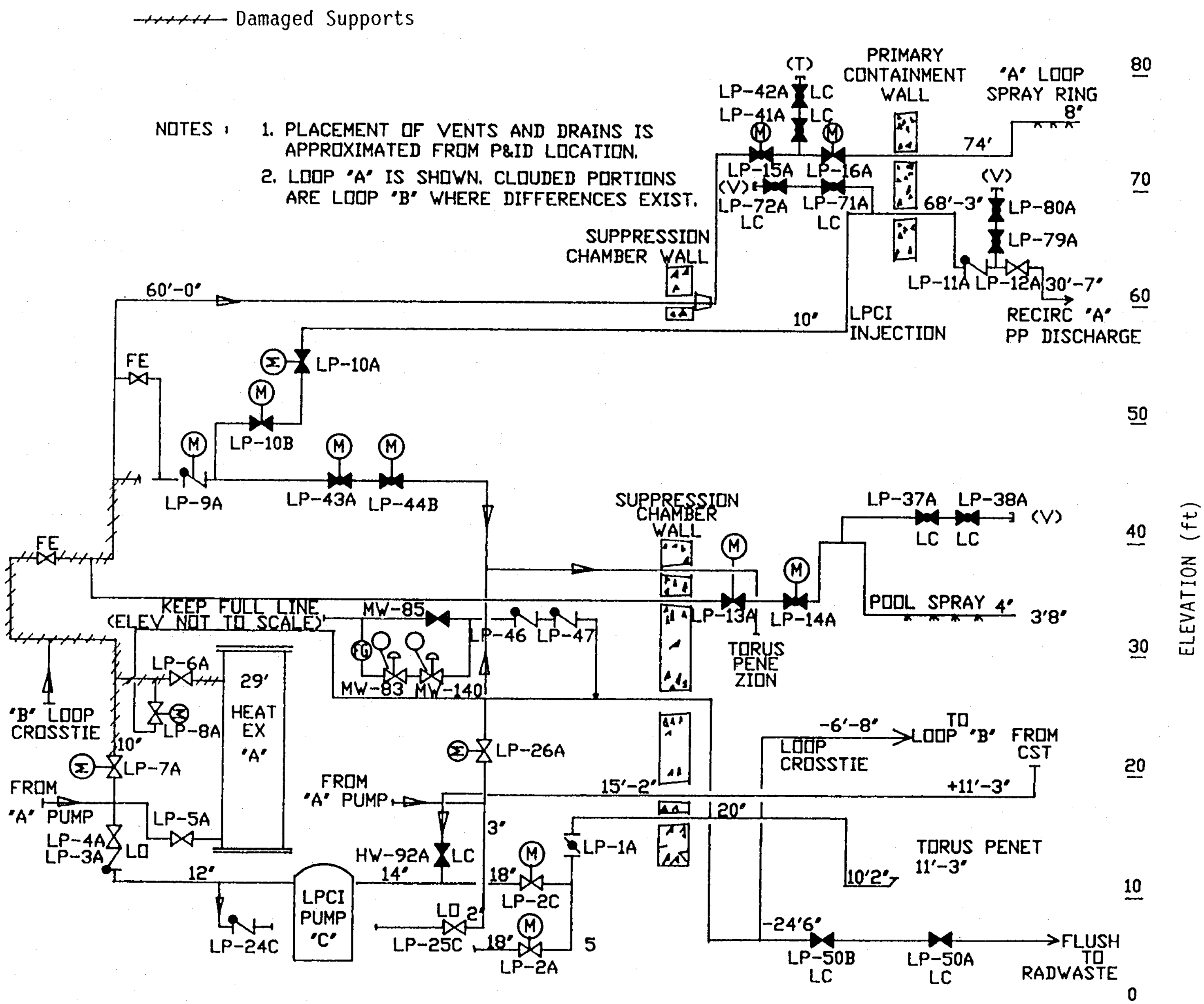


Figure 10-2. Elevation Diagram for LPCI System

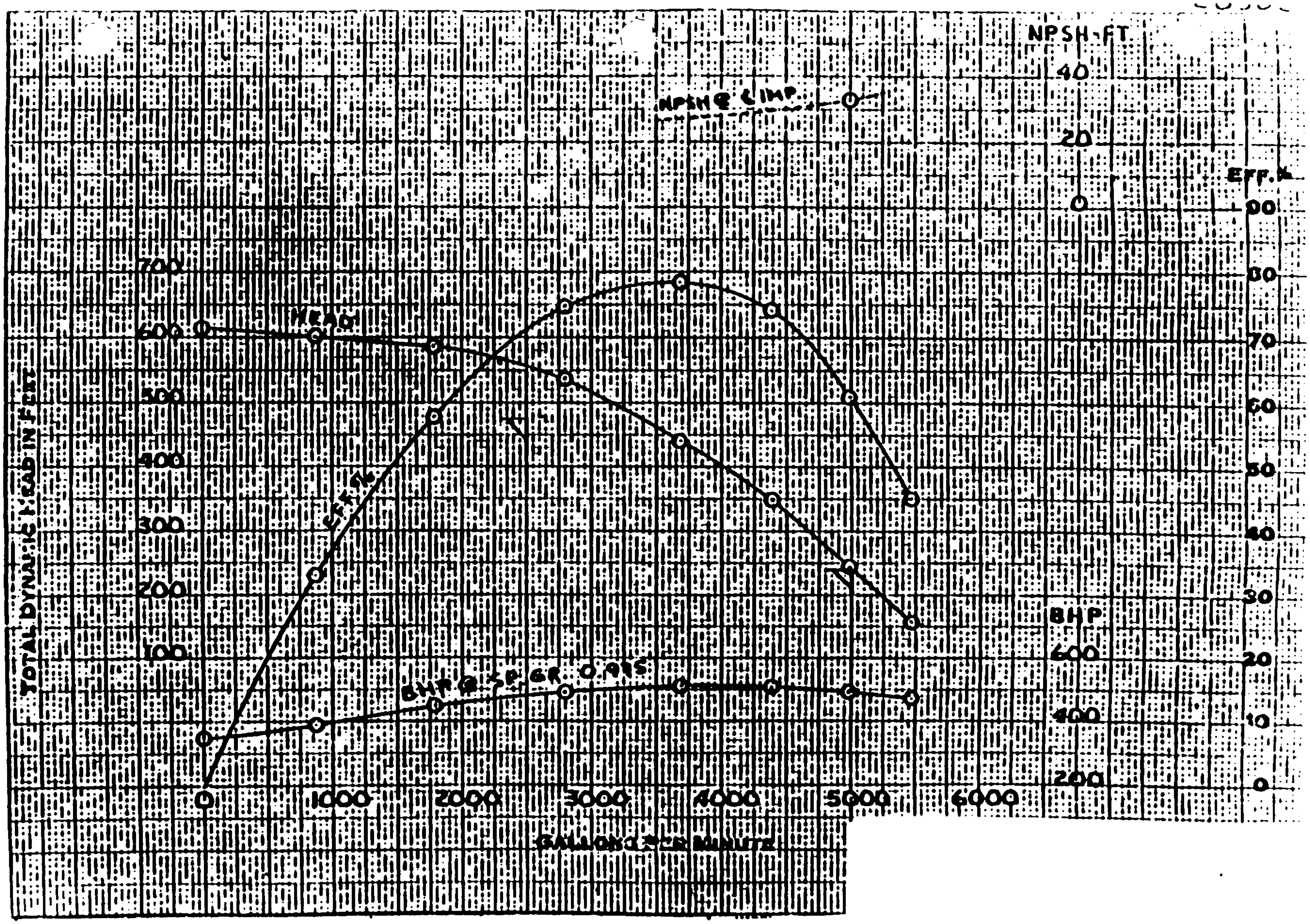


Figure 10-3. Pump Characteristic

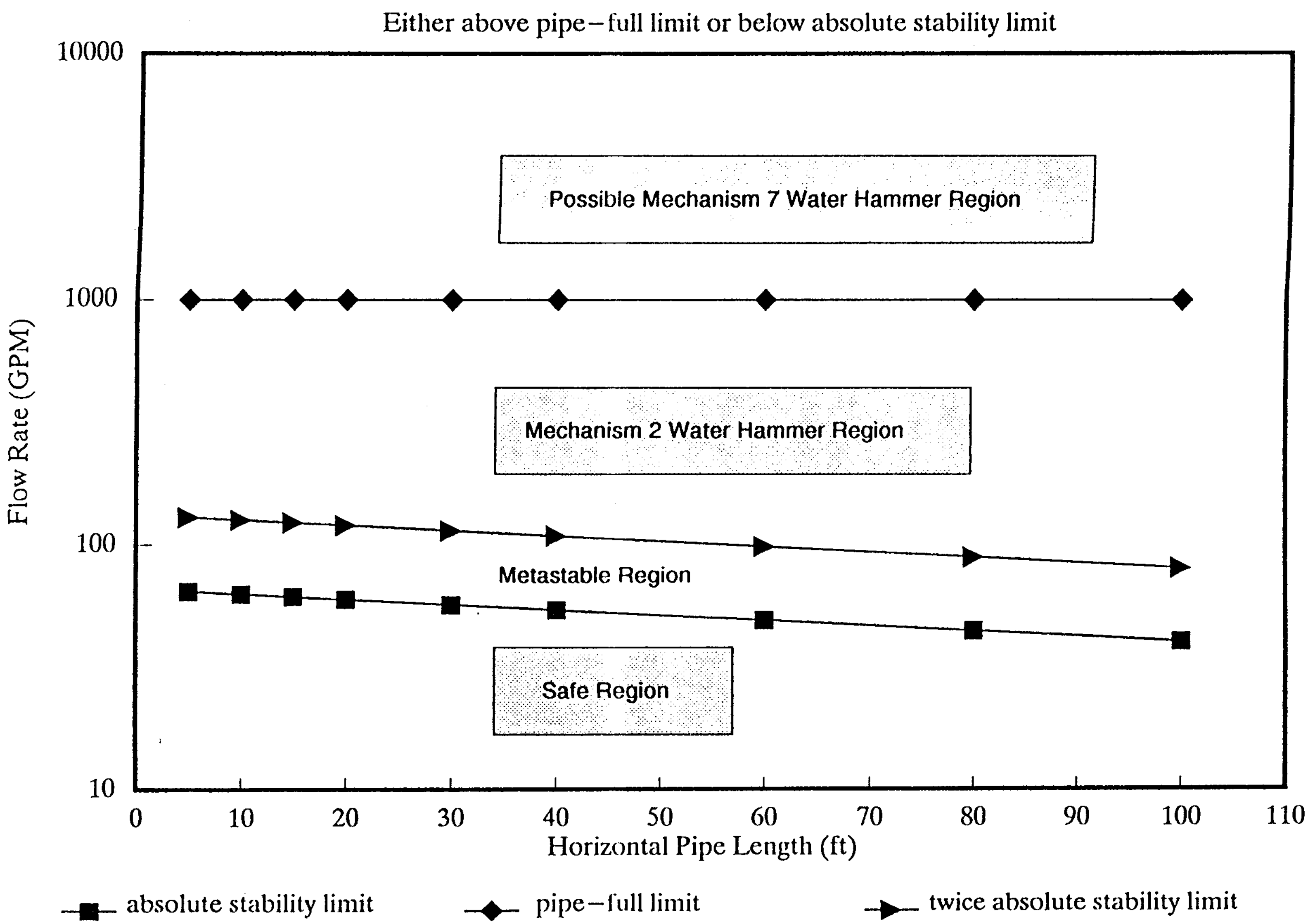
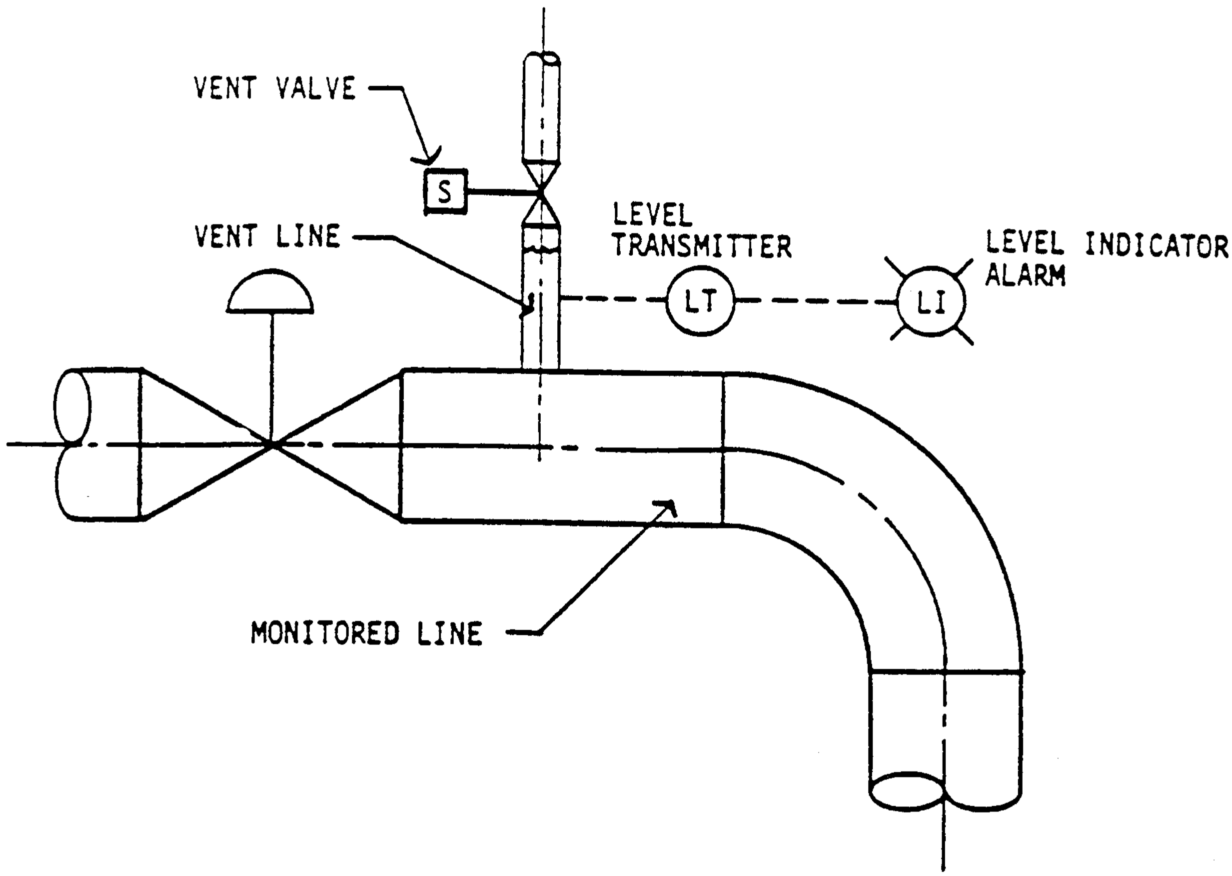


Figure 10-4. Mechanism 2 - Acceptable Pipe Filling Rate for 12" Pipe



LEVEL TRANSMITTER IN VENT LINE DETECTS THE
INCIPIENCE OF VOIDING AND PROVIDES ALARM.

Figure 10-5. Conceptual Design of Possible Void Detection Scheme

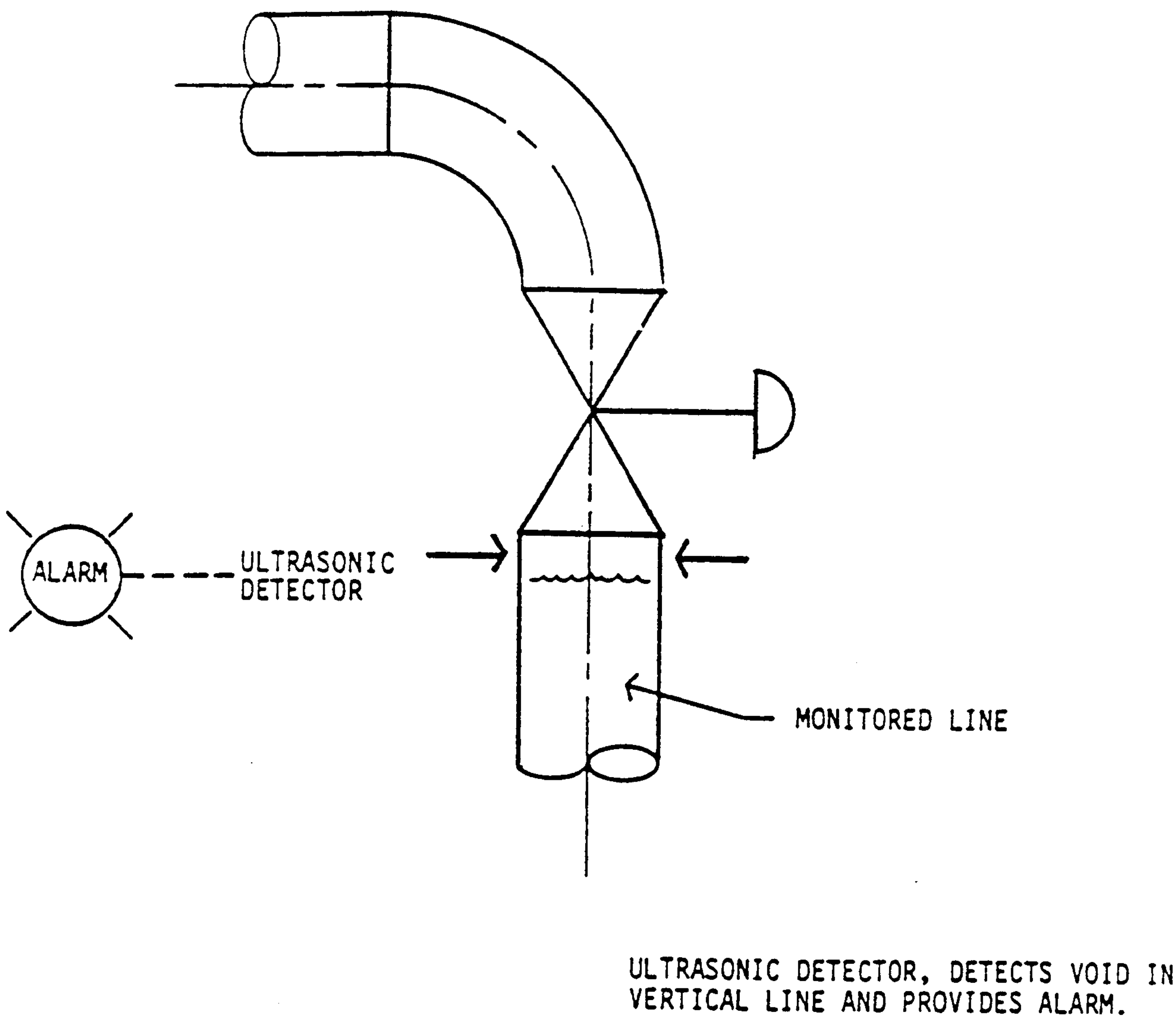


Figure 10-6. Conceptual Design of an Alternate Void Detection Scheme

Section 11

ISOLATION CONDENSER SYSTEM IN A BWR

SYSTEM FUNCTION

The Isolation Condenser (IC) system is required to remove heat from the reactor, starting five minutes after scram, at a rate equal to the heat generation rate of the reactor core. System operation must continue for at least 30 minutes without makeup to the condenser shell.

SYSTEM CONFIGURATION, MODES OF OPERATION AND COMPONENT DATA

Configuration

The IC system takes steam directly from the reactor vessel through a 14-in. line, that changes to 16-in. line, branching into two 12-in. lines that lead to two separate U tube sides of a shell and tube heat exchanger. On the shell side an inventory of cooling water is present. The cooling water evaporation is vented through a vent system to the atmosphere. The condensate (in the tube side) returns to the reactor via two 8-in. lines that combine into one 10-in. line that connects to one of the 28-in. reactor circulating pump suction lines.

Figure 11-1 shows a simplified elevation diagram of the system. The condenser tube bundles are approximately 25 ft above normal reactor water level.

Figure 11-2 gives some geometrical details of the steam supply line.

Isolation Condenser System Operating Modes

The isolation condenser system is not operational during normal plant operating conditions. The system has the following emergency operating modes.

Automatic Operation

The isolation condenser system is placed into operation by opening the condensate return outboard isolation valve (IC-3). Automatic initiation occurs upon receipt of one of the following signals.

a) Reactor vessel water level at -48 in.

b) Reactor pressure greater than 1085 psig for 15 s.

The system can be reset after the initiation signal clears by a switch in the control room.

Manual Operation

The isolation condenser system can be operated manually by placing the "Normal/Throttle" switch in the control room panel for the condensate return outboard isolation valve (IC-3) in the "Throttle" position. Throttling this valve allows the operator to control the reactor vessel cooldown rate.

Operation from Outside the Control Room

The isolation condenser system can be operated from outside the control room as follows. The steam line isolation valves (IC-1,2) and the condensate return line inboard isolation valve (IC-4) utilize control room isolation switches located near their respective motor control centers. Each control room isolation switch has two positions, "Normal" and "Emergency." In the "Normal" position, the valve is operated from the control room. In the "Emergency" position, the valve is operated from a local rack located in the reactor building outside the drywell. Manual control of the condensate return line outboard isolation valve (IC-3) is achieved by placing the breaker located on motor control center in the "Off" position.

Interfaces with Other Systems

a) Recirculation System: The condensate return line is routed to the suction line of loop B of the recirculation system.

b) Nuclear Boiler System: The steam line vent is routed to main steam line A downstream of the main steam isolation valves.

c) Fire Protection System: The fire protection system is the preferred source of shell side makeup water.

d) Condensate Transfer System: The condensate transfer system is available as a backup source of shell side makeup water.

e) Instrument Air System: The instrument air system supplies air to the air-operated steam line vent valves.

f) Process Sampling System: Grab samples can be taken at the following points in the isolation condenser system:

- Shell side makeup line
- Shell side drain line
- Condensate return line

Control Logic

a) System Initiation

The isolation condenser system is automatically initiated when reactor vessel water level falls to -48 inches or when reactor pressure exceeds 1085 psig for greater than 15 seconds. The 15 second time delay prevents spurious system initiations during turbine trips. Initiation due to vessel Low-Low water level requires manual reset to prevent excessive cycling of valve IC-3. The system can also be initiated manually. System initiation consists of opening the condensate return outboard isolation valve (IC-3) as discussed before.

b) System Isolation

A Group 4 isolation signal closes the steam line isolation valves (IC-1,2), condensate return isolation valves (IC-3,4) and steam line vent valves (IC-6,7). A steam or condensate flow indication of 300% of normal will initiate a Group 4 isolation.

c) Control Room Instrumentation

The indications provided in the control room are: steam line pressure (0 to 1500 psig); shell side level (0 to 11 ft); vent line radiation level (0.1 mR/hr to 1 R/hr); and steam leak detection by means of area temperature (100 to 375°F). A two-pen recorder on a control room panel gives trending information on shell side level (0 to 100%) and shell temperature (0 to 250°F).

d) Alarms

The following alarms are provided in the Control Room.

- Isolation condenser level (Low = 69 in., High = 80 in., and High-High = 95 in.)

- Isolation condenser high temperature. Set at 120°F in either outlet line.

- Isolation condenser valves off normal. Valves IC-1,2,4,6,7 not open, Valve IC-3 not closed, or control room indicating switch not in "normal" position.

- Isolation condenser line break. Set at 300% of normal steam or condensate flow.

- Isolation condenser shell high temperature. Set at 120°F.

- Isolation condenser vent high radiation. Set at 10 mR/hr.

- Isolation condenser vent radiation monitor downscale. Set at 0.1 mR/hr.

- Isolation condenser control switch off "normal", loss of control power.

- IC-1,2,3,4 valve operator motor overload.

Filling/Venting/Draining

The supply line has two drains. These drains have steam traps and the drains connect to the main condenser. Recently the drains were routed to the torus. The supply line connects to 3/4-in. vent line leading to the main steam header. The supply line is also equipped with a 1-in. relief valve (see Figure 11-1).

Component Data

a) Valves

Motor operated valves are conventional gate valves with electric motor driven operators to provide automatic remote control.

The outboard isolation valves IC-2 and 3 and the shell side fill valve IC-10 are DC powered. The inboard isolation valves IC-1 and 4 are AC powered.

Table 11-1 gives the IC motor operated isolation valve data.

b) Isolation Condenser

The shell side contains more than 15,500 gallons of water which absorbs the residual heat by boiling at atmospheric pressure.

The Isolation Condenser is a 132-in. diameter, atmospheric tank with two U tube bundles, each with 121 stainless steel tubes of 1-in. outside diameter.

WATERHAMMER EXPERIENCES

Four incidents were reported in References (1) to (3). In the summary statistics table found in the Task 2 report (4), the isolation condenser was combined with the RHR system. It is noted that ICs were only installed in the very early BWR plants.

Each event was analyzed in the Task 2 Root Cause Report (4) to determine the areas of each system which are prone to water hammer, the specific water hammer mechanism, and root cause. The remedial actions taken by the utility to preclude future occurrence of a similar water hammer were described. Appendices A and B of (4) presented the BWR and PWR utility water hammer databases and Appendix C therein listed the utility plant codes used. Areas prone to water hammer were identified in typical schematics of each system discussed.

One incident at the plant reviewed is described below. This event occurred after a plant trip and subsequent Reactor Pressure Vessel water level rise.

WATER HAMMER EVENT 1: WATER SLUGS IN THE STEAM SUPPLY LINE

Event Description

Prior to the trip and release incident, the plant was operating at a steady power level of 100 percent. Routine surveillance and maintenance activities were being conducted at the time.

At t = 0, immediately before the trip, the main transformer deluge system was actuated by automatic initiation and the 345 KV side of the main transformer arced over to ground and tripped the main generator. At the time of the trip an operator was in the area of the isolation condenser and noted that internal rumbling started within a minute and he presumed that the IC had gone in service. He also noted that the smaller piping attached to the IC was vibrating. Other personnel who were working in the yard within line of sight of the IC vent noted that "puffs" of steam were coming from the vent and that they continued for approximately 8 to 10 minutes.

A generator trip of this nature will always cause a turbine trip, and whenever the plant is operating above 45 percent power, a reactor trip is generated by closing of the turbine stop valves. At the time of the trip, the reactor pressure increased from 1030 psig to 1047 psig, which is expected as the turbine stop valves will close faster than the turbine bypass valves open. This short pressure transient is terminated by the opening of the turbine bypass valves. The reactor water level dropped approximately 40 in. immediately following a reactor trip due to the void collapse. The level decrease will cause a pressure drop to a point below 970 psig, which is the approximate setpoint of the turbine pressure control system at this time. As the level control system made up the reactor with subcooled water, the pressure would decrease further.

During this period, one operator noticed that the lights on the IC condensate return valve momentarily lost the full closed indication. There was no reason for the valve to open automatically as a reactor pressure of 1085 psig must be sustained for 15 seconds for initiation. In addition, once it is initiated the valve will go fully open. There are no circumstances that could cause partial openings of the valve. An operator was dispatched to deenergize the valve breaker and to check the valve position. At t = 8 mins the operator reported that the valve was in the full closed position.

By t = 3 mins the main steam line pressure had decreased to less than 880 psig and a full closure of the main steam line isolation valves occurred. This trip is active only in the RUN mode and is intended to prevent power operation at low reactor pressures and provide steam line break protection. The isolation valve closure signal can be bypassed by removing the mode switch in RUN and is a conservative action on the part of the operator.

During, or shortly before this period of time, the reactor level had returned to normal and it was noted that one feedwater regulation valve had locked in the "as is" position and was not going closed as it should once level requirements are satisfied. The reactor feedpumps were tripped and the vessel level was stabilized at a point 33 in. above the normal level. A level 33 in. above normal is approximately even with the bottom of the isolation condenser steam inlet nozzle and is approximately 4 ft below the main steam line nozzles.

After the closure of the main steam isolation valves, the pressure started to increase as no heat sink was in service at the time. The operator then proceeded with steps necessary to open the main steam line isolation valves and return the main condenser to service as the prime heat sink.

At t = 8 mins, as stated previously, the IC condensate return valve was deenergized and the operator reported that the valve was found in the full close position.

At t = 11 mins the main steamline isolation valves were re-opened thus restoring the main condenser to service as the prime heat sink. The reactor pressure had risen to a peak of 1043 psig at the time of re-opening.

The re-opening of the isolation valve caused a level surge which carried the level above the isolation condenser steam inlet nozzle for two to three minutes. The level then dropped back to a point below the isolation condenser nozzle and continued to drop to be within normal range. During this period the reactor pressure was reduced to and maintained at 970 psig.

Reports from the area in the yard indicated that the amount of steam coming out from the isolation condenser vent had dropped off considerably which was probably due to the drop in reactor pressure.

By t = 22 mins, the reactor pressure was steady at 970 psig and the level was being returned to normal. The recovery from the reactor trip was in the final stages and the only off-normal situation existing was the continued temperature change in the isolation condenser. The temperature change was watched and was presumed to be stabilizing, as the condensate return valve was known to be in the closed position.

At t = 51 mins, personnel in the area of the isolation condenser vent noted that both steam and water were coming from the isolation condenser vent, and proceeded to secure the area due to the potential for contamination.

The operations personnel secured the second "in line" isolation condenser condensate return valve at t = 51 mins, and continued to monitor the conditions. At this time the operators thought that the first condensate return valve was leaking by and that closing the second valve would terminate the boiling in the isolation condenser.

At t = 66 mins, the operator received alarm from the IC vent radiation monitor and had received reports that steam and water were still coming out of the vent. The operator then closed the isolation condenser steam inlet valves, and the steam from the isolation condenser started to decrease at this time.

At t = 71 mins, the steam from the isolation condenser vent had stopped and the vent radiation monitor was beginning to decrease.

Mechanisms Responsible for the Event

The "steam-propelled water slug", severe water hammer Mechanism 5 and/or "water flow into a void", Mechanism 7 appear to be the mechanisms responsible for the event.

Analysis of Root Causes

The accounts of the event as described above suggest two potential transients, these are:

A. Following a reactor transient involving large vessel depressurization, the water column (or part of) in the vertical section above the water in the IC tubes (which is at relatively high temperature due to its contact with the steam from the reactor at plant normal operating conditions) would flash. This would result in a water slug reaching the horizontal section of the steam supply line. If the reactor transient results into reactor trip, this causes the isolation of the IC vent from the main steam line (valve IC-6 closed upon reactor trip). Prior to that the connections of the drains to the main condenser may lead to subsequent acceleration of the water slug. This sequence is conjectured based on observations and discussions with the plant personnel. Figure 11-3 illustrates the events of this transient.

   This transient thus falls under the steam-propelled water slug Mechanism 5.

B. During plant shutdown, if feedwater flow is not terminated quickly, the reactor water level may reach the nozzle of the IC steam supply system. With a reactor trip and Valve IC-6 thus isolated, the vent to condenser will result in a water slug to be carried into the steam line. Figure 11-4 illustrates the sequences of this transient.

Sketch 2 in Figure 11-2 depicts the situation while flashing of the water in the vertical segment above the IC takes place due to a reactor depressurization. The arrow shown suggests the direction of water slug movement.

After depressurization ceases, and/or as the pressure in the vessel increased, the slug movement reverses as shown in sketch 3 of Figure 11-3.

This transient falls under Mechanism 7, water flow into a voided line.

Unfortunately the records of reactor pressure variation with time, during the period of interest of this event are not available. Also, the exact timing and the duration of the rise of water in the RPV up to the IC nozzle is not known. Thus, it is not possible to state firmly which type of transient occurred, type A or type B.

Adopting some simplifying assumptions, one may use the model in (5) to get estimates for the forces as given below. One must recognize at the outset the difficulty in selecting the input values for these calculations due to the large uncertainty in the data available.

One may assume the pressure differential that would act on the slug and calculate the characteristic velocity V_0 based on the equation below:

$$V_0 = \sqrt{\frac{P_0 - P_1}{\rho_f}}$$

Then select from Figure 11-5 the situation that is most representative for the case under consideration. Corresponding to that situation, the appropriate value for V_1/V_0 depending on the case number from Table 11-2 can be used. Note that the idealized model requires the specification of the initial slug length L_0 and/or α(the void fraction) as well as L the final slug length for some situations.

The dynamic force due to impact of the slug against a dead end "F_i", can be calculated from Joukowsky's equation

$$F_i = (\rho . a . V_1)\ A \qquad (11\text{-}1)$$

where

a = pressure wave propagation speed

A = pipe cross-sectional area

ρ = fluid density

Assuming ρ = 58 lb/ft^3, a = 4000 ft/s and for 12-in. pipe diameter (corresponding to the steam supply piping - see Figure 11-2), A = 113 in^2, one can calculate the impact force "F_i" corresponding to assumed pressure differentials.

For transient A, if one uses situation "a" of Figure 11-5, then the terminal velocity can be computed by using the case 1 of Table 11-2. Figure 11-6 gives the slug impact force in kips for various values of pressure differentials acting on the slug. The results of this figure shown that if a slug develops to fill the cross section and is accelerated enough over a distance to reach its terminally velocity, significant loading will be encountered. For instance a slug of the type depicted under situation "a" in Figure 11-5 under a pressure differential of 200 psi will cause an impact load of 715 kips. It should be noted that the water slug will be dissipating as it travels along the pipe. In the Task 5 Assessment Guidelines (6) it was determined that the slug dissipates completely in about 8 times the effective initial slug length. This effective slug is defined as the length of the slug that fills the entire cross section of the pipe.

For transient B, either situations "b" or "c" of Figure 11-5 may be encountered. If the water level rise in the RPV is sustained due to continued feedwater flow, then situation "b" would be most representative. For this situation and assuming the initial slug length L_0 is equal to zero, and assuming values of α = 0.25, 0.5 and 0.8, using case 3 in Table 11-2, the impact force changes with pressure differential across the slug are shown in Figure 11-7.

Water Hammer Root Causes

The presence of a relatively hot condensate inventory at the top of the condensate in the tube side of the isolation condenser will make the steam supply line vulnerable to transients of the type A, when the reactor undergoes large depressurizations.

The lower the elevation of the inlet nozzle of the steam supply line in the reactor pressure vessel, the higher the potential for water carryover into the steam supply line (transient B) above.

Corrective Measures

The ruptured tube was repaired and larger capacity supports were installed.

To avoid transient B, the control logic was used through adoption of quick trip of feedwater is an effective measure, however, the effects of such fix should be on the reactor and the feedwater system must be evaluated carefully.

SYSTEM EVALUATION

Normal Transients

From the section on plant configuration, it is seen that the IC system operation starts by opening valve IC-3 (Figure 11-1). Prior to that, the return line would be full of water (water is also expected to fill the tube bundle in the IC and the vertical portion of the supply line above the IC, see Figure 11-1). Since this valve opening time is relatively long, (note however that for gate valves the first part of the opening amounts to the effective opening) and by that time the liquid is almost stagnant, this valve opening transient is relatively weak.

For this plant, the piping supports were not sized based on the consideration of this transient. However, as a result of events of the type described in the section on water hammer experiences, the steam supply lines were supported quite heavily. Refer to the marked piping in Figure 11-1, where support damage was encountered and hence replacement with heavier supports took place.

Severe Transients

From examination of the incidents, discussions with plant operators and engineering personnel it is concluded that three severe transients may occur. These are of steam-propelled water slug, Mechanism 5. In the incidents noted in the section on water hammer experiences, the IC system piping supports that encountered damage were on the steam supply line (refer to marked Figure 11-1). Out of the three potential transients, two have already been discussed in the section on water hammer experiences. The third is discussed below:

> Under situations where low reactor water level is reached, *automatic initiation* of the IC system starts. If the low reactor water level is preceded by low pressure it would result in flashing of the water in the vertical supply pipe segment directly above the IC tubes. Thus, a water slug would reach the horizontal segment of the steam supply line (similar to Case a above). Upon the initiation of the IC system, i.e., opening Valve IC-3, this water slug will be accelerated thus yielding a severe transient (again of the type of Mechanism 7).

It should be noted that in discussions with one of plant operators, he was pleased with the IC as a dependable system. Comments were expressed that severe water hammers are encountered when the IC system is automatically started. The first two transients noted in the section on water hammer experience do not involve the operation of the IC. Only this third possible transient involves the automatic operation of the IC system. The probability of the occurrence of this transient is small. Further, this transient is expected to be the severest among the three. The incident described in the section on water hammer experiences involves an IC tube rupture. In this plant, the vent line connection to the condenser was rererouted to the torus. To avoid transient B, the plant has modified feedpump trip logic, causing quicker feedwater flow reduction, hence averting water level rise to the IC nozzle.

Prevention/Mitigation and Accommodation

Through good drainage and venting, accumulation of water in the steam line can be avoided. Proper sloping of the horizontal portions of the steam supply line is necessary.

To minimize transient A, the vertical pipe segment above the water tubes should be minimized to limit the water inventory that may flash upon depressurization. Venting to torus rather than the main condenser would be helpful.

To avoid transient B, a control logic used as adopted in this plant, i.e. quick trip of feedwater is an effective measure, however, the effects of such fix on the reactor and the feedwater system must be evaluated carefully.

To accommodate a Mechanism 5 transient, the piping supports would generally have to be quite large.

Other Observations

The use of a gate valve IC-3 to control the IC system operation is not advisable. The use of globe valve will give better control. Further, the sizing of that valve should take into effect the possible range of operation for the IC particularly as it relates to the shell water temperature range (80 to 212°F).

REVIEW OF OPERATING, TESTING AND MAINTENANCE PROCEDURES

Operating procedures for IC system in this plant appear to be adequate to meet normal transients.

Discussions with plant operators indicate that shell water loss is minimal and no water replenishment is necessary during normal plant operation.

Because of the thermal transients that the tubes undergo when the system is placed in automatic operation, frequent inspection of the tubes is recommended. The isolation condenser disassembly and assembly procedure suggests slow warming up and cooling off. It is noted that IC retubing was performed at the plant reviewed after the plant was in operation for about seven years.

STRENGTHS AND WEAKNESSES FOR WATER HAMMER PREVENTION

Strengths

The steam supply line has two drains. These drains have steam traps and the drain connect to the main condenser. Recently the drains were routed to the torus. The supply line connects to 3/4-in. vent line leading to the main steam header. The supply line is also equipped with a 1-in. relief valve (see Figure 11-1).

Through good drainage, venting, accumulation of water in the steam line can be avoided. Proper sloping of the horizontal portions of the steam supply line is necessary.

To minimize flashing, the vertical pipe segment above the water tubes should be minimized to limit the water inventory that may flash upon depressurization. Venting to torus rather than the main condenser would be helpful.

To avoid reactor water carryover from the vessel into the steam supply line, the control logic use of quick trip of feedwater is an effective measure, however, the effects of such fix should be on the reactor and the feedwater system must be evaluated carefully.

Weaknesses

The use of a gate valve IC-3 to control the IC system operation is not advisable. The use of globe valve will give better control. Further, the sizing of that valve should take into effect the possible range of operation for the IC particularly as it relates to the shell water temperature range (80 to 212°F).

REFERENCES

1. NUREG-0927, Revision A, Evaluation of Water Hammer Occurrence in Nuclear Power Plants, 1984.

2. NUREG/CR-2781, QUAD-1-82-018-2203, Evaluation of Water Hammer Events in Light Water Plants, 1982.

3. NUREG/CR-2059, EGG-CAAD-5629, Compilation of Data Concerning Known and Suspected Water Hammer Events in Nuclear Power Plants, 1982.

4. Van Duyne, D. A., Yow, W., and Sabin, J. W., "Water Hammer Prevention, Mitigation, and Accommodation, Task 2 - Root Cause Analysis for Plant Water Hammer Experience," EPRI RP-2856-3, Task 2 Report, December 1989.

5. Van Duyne, D. A., and Yow, W., "Water Hammer Prevention, Mitigation, and Accommodation, Task 1 - Plant Water Hammer Experience." EPRI RP-2856-3, Task 1 Report, November 1989.

6. NUREG-0291, NRC-1; An Evaluation of PWR Steam Generator Water Hammer., Final Technical Report, June 1977.

7. Van Duyne, D. A., Rooney, J. W, and Sabin, J. W., "Water Hammer Prevention, Mitigation, and Accommodation. Task 5 - Water Hammer Prevention, Diagnostic and Assessment Guidelines." EPRI RP-2856-3, Task 5 Report, October 1990, draft report.

Table 11-1

IC MOTOR OPERATED ISOLATION VALVES DATA

Valve	Designation	Type	Stroke Time (Seconds)	
			Opening	Closing
Supply	IC-1	Gate		24*
Supply	IC-2	Gate		24
Return	IC-3	Gate	7	19
Return	IC-4	Gate		19

*given as maximum opening time in plant technical specifications.

Table 11-2

SLUG IMPACT TERMINAL VELOCITY

Case	Reservoir	Initial Slug Length	Void Fract-ion	V_1/V_0
1	Yes	0	0	1
2	Yes, Inlet Loss	0	0	$\sqrt{\frac{1}{(1+K)}}$
3	Yes	0	α	$\sqrt{\alpha}$
4	Yes	L_0	α	$\sqrt{1-\left(\frac{L_0}{L}\right)^2}$
5	No	L_0	α	$\sqrt{\frac{\alpha}{1-\alpha}}\sqrt{1-\left(\frac{L_0}{a.L_0+(1-\alpha).L}\right)^2}$

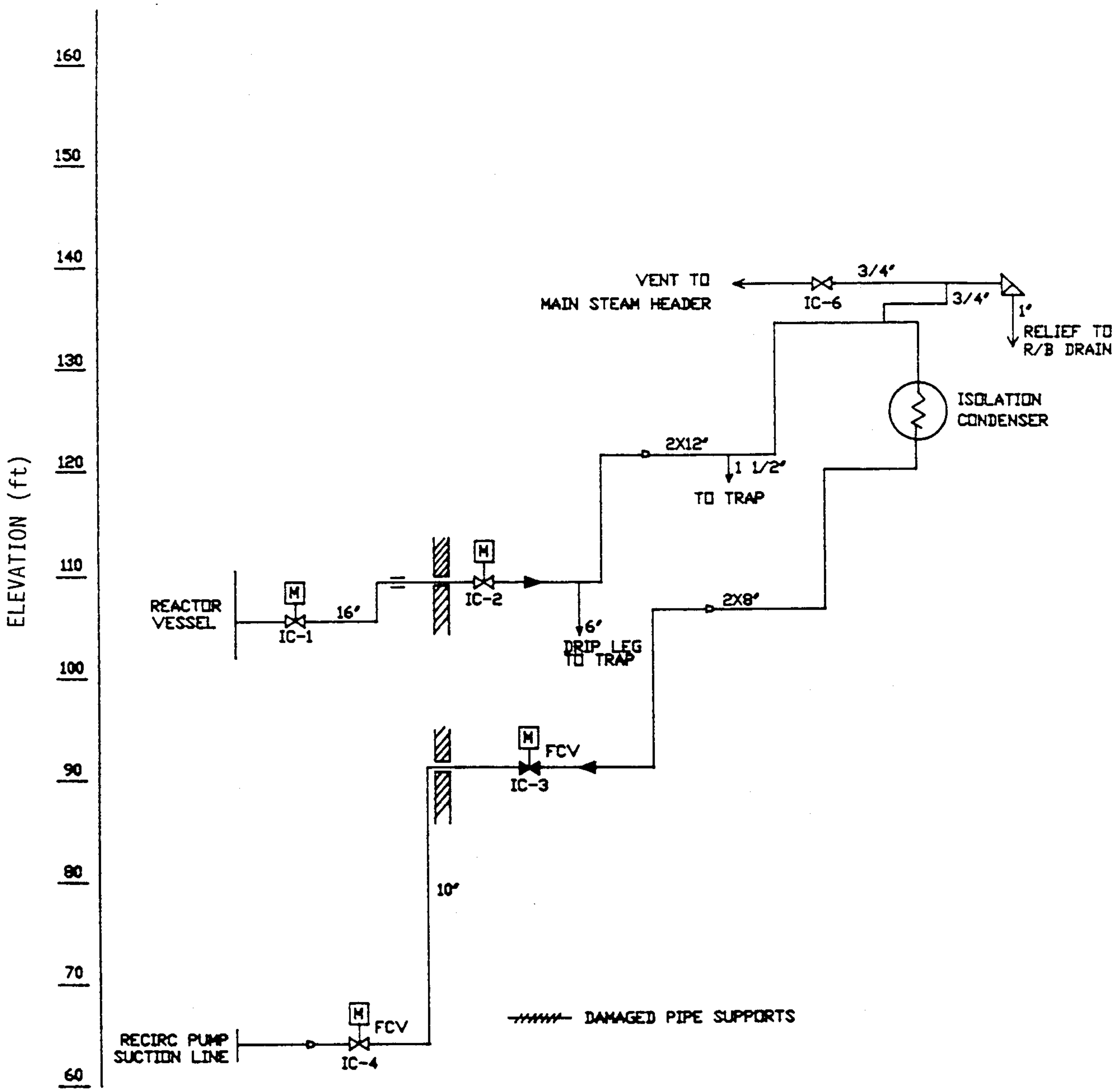


Figure 11-1. Elevation Diagram for Isolation Condenser System

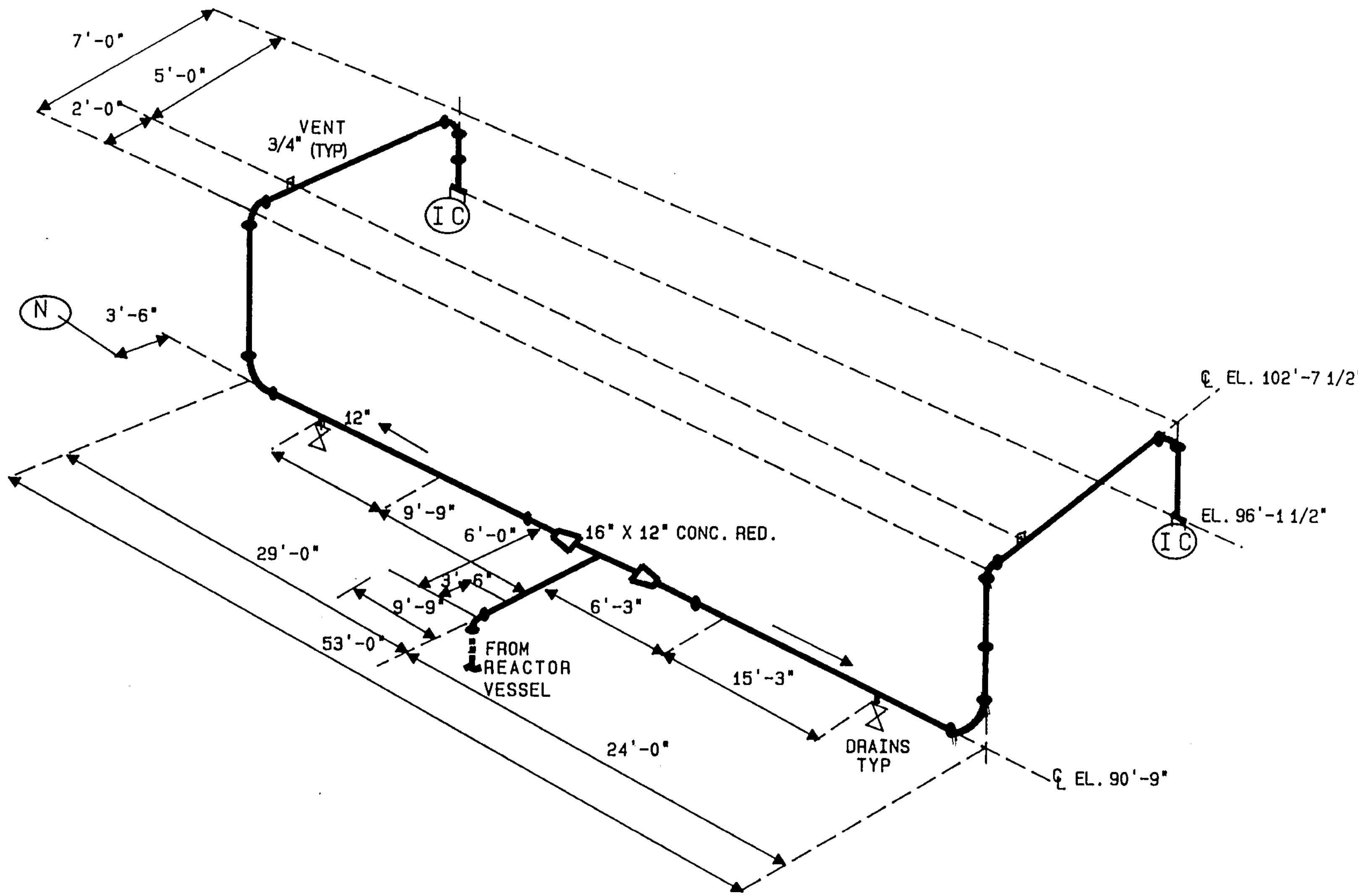


Figure 11-2. Geometry of Steam Supply Line to the Isolation Condenser

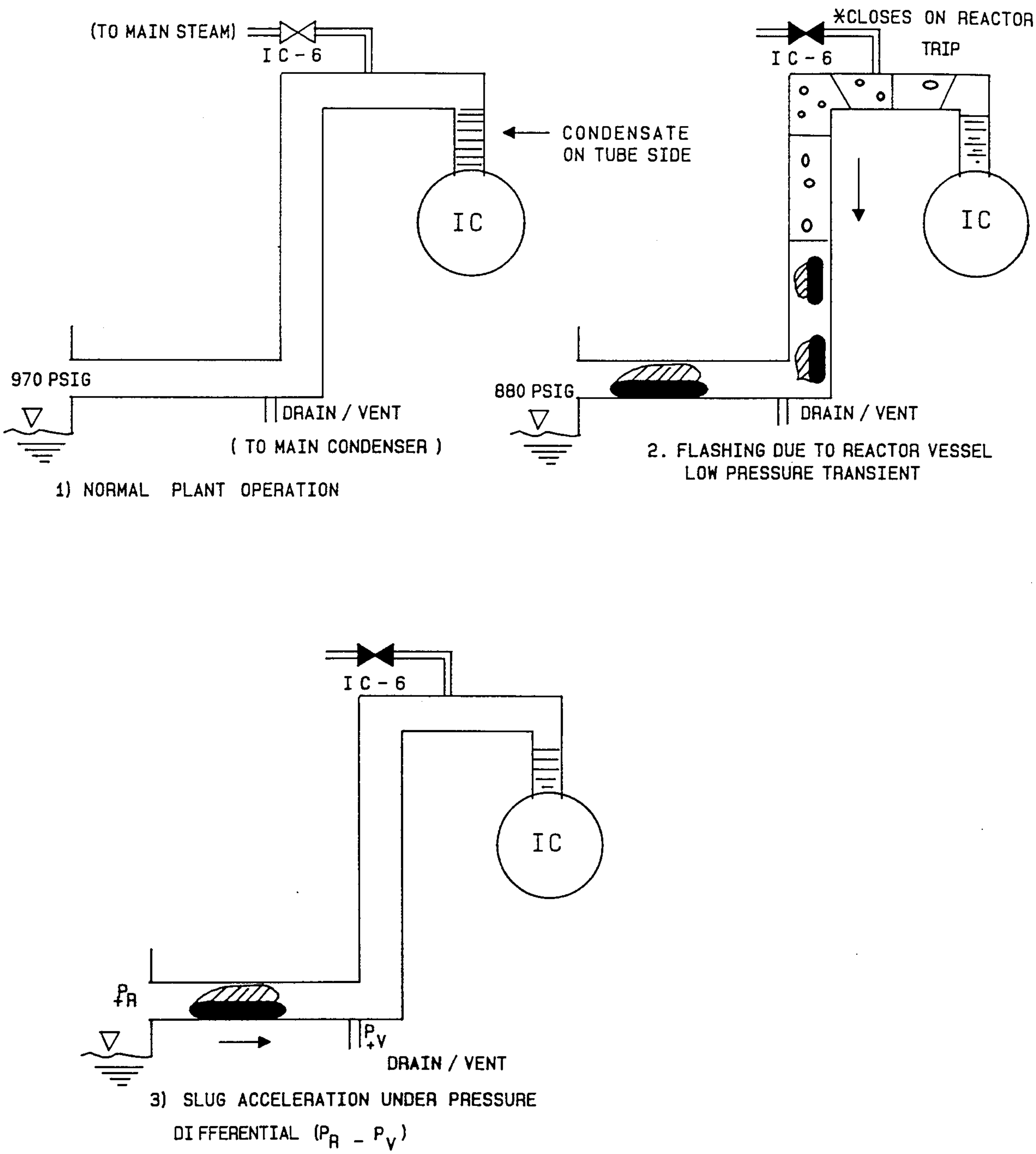


Figure 11-3. Schematics for Sequence of Events for Transient A

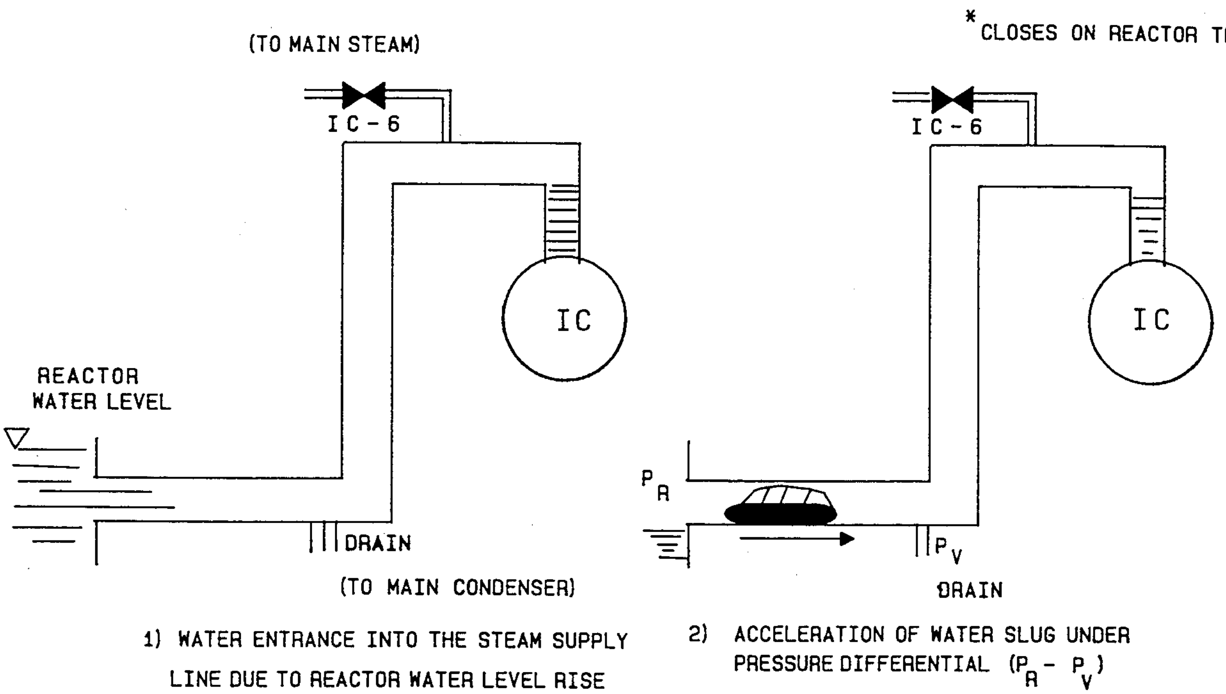
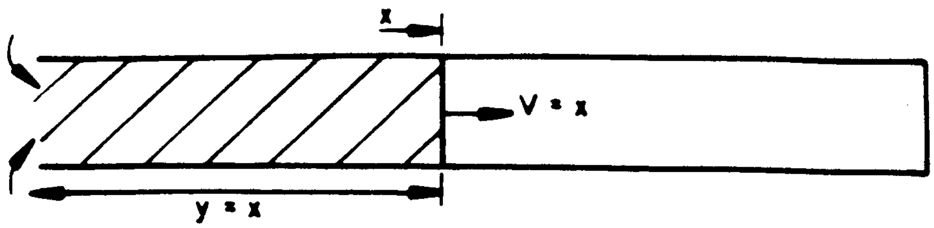
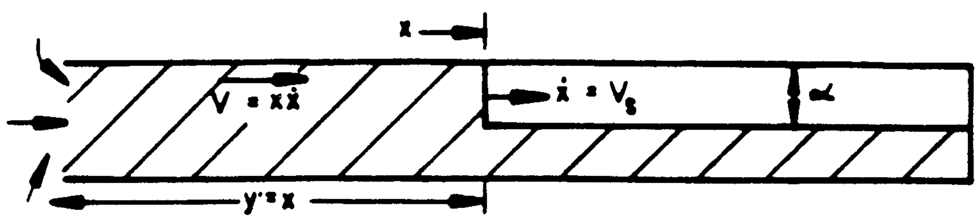


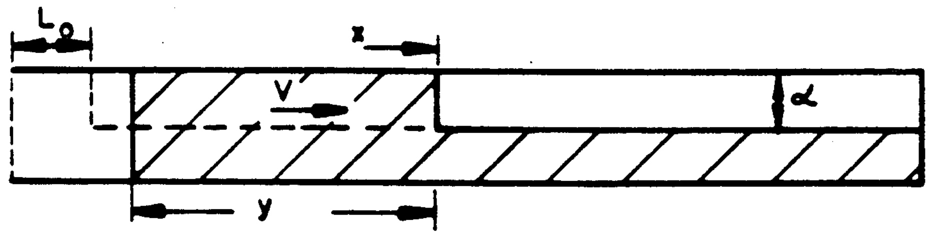
Figure 11-4. Schematics Sequence of Events for Transient B



(a) SLUG FED BY A RESERVOIR. PIPE INITIALLY EMPTY.



(b) SLUG FED BY A RESERVOIR. PIPE PARTLY FULL INITIALLY.



(c) NO RESERVOIR. INITIAL LENGTH L_o. PIPE PARTLY FULL INITIALLY.

Figure 11-5. Several Idealized One-Dimensional Models of Slug Motion

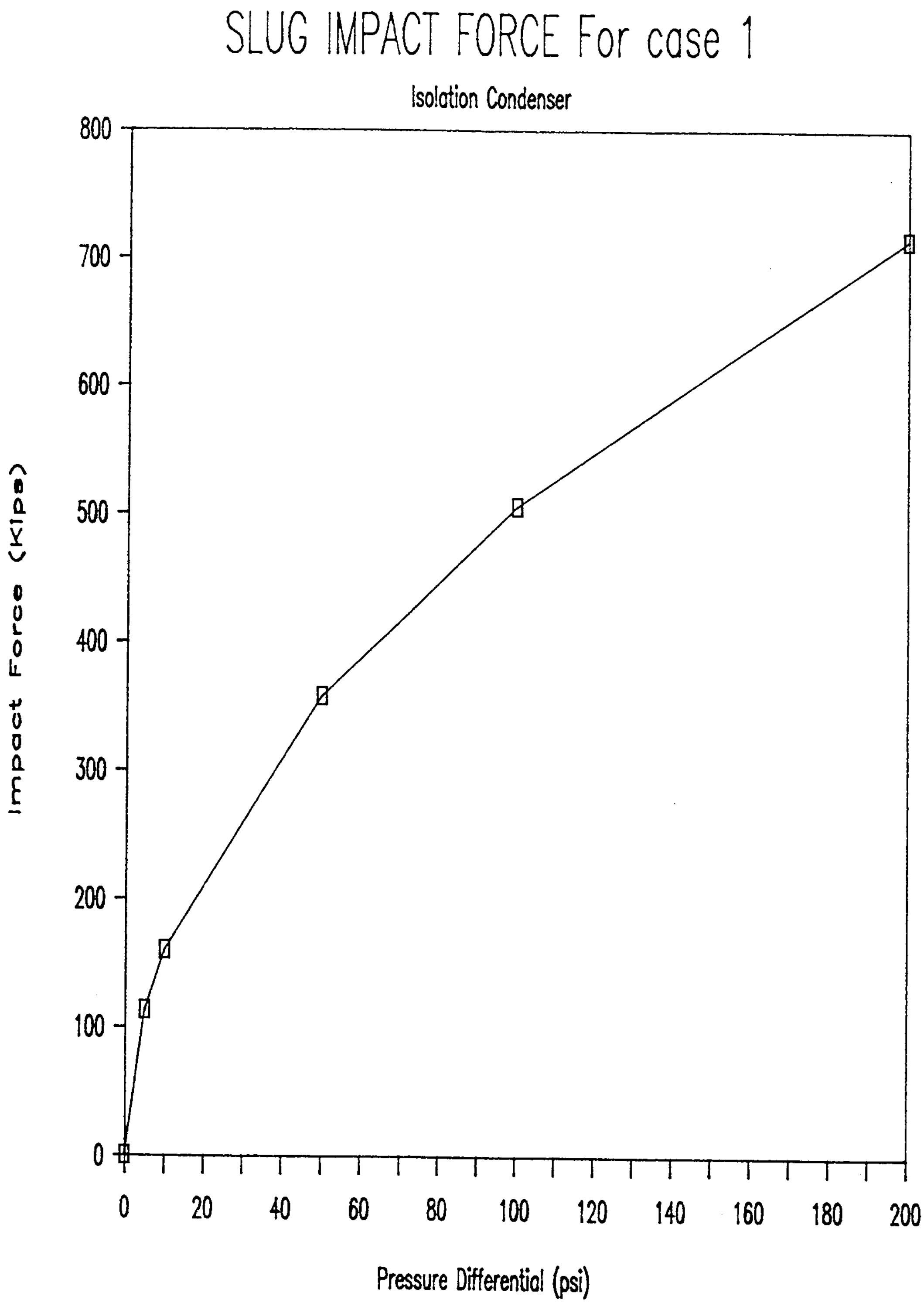


Figure 11-6. Slug Impact Force Versus Pressure Differential Over the Slug (for Situation A in Figure 11-5 and Case 1 in Table 11-1)

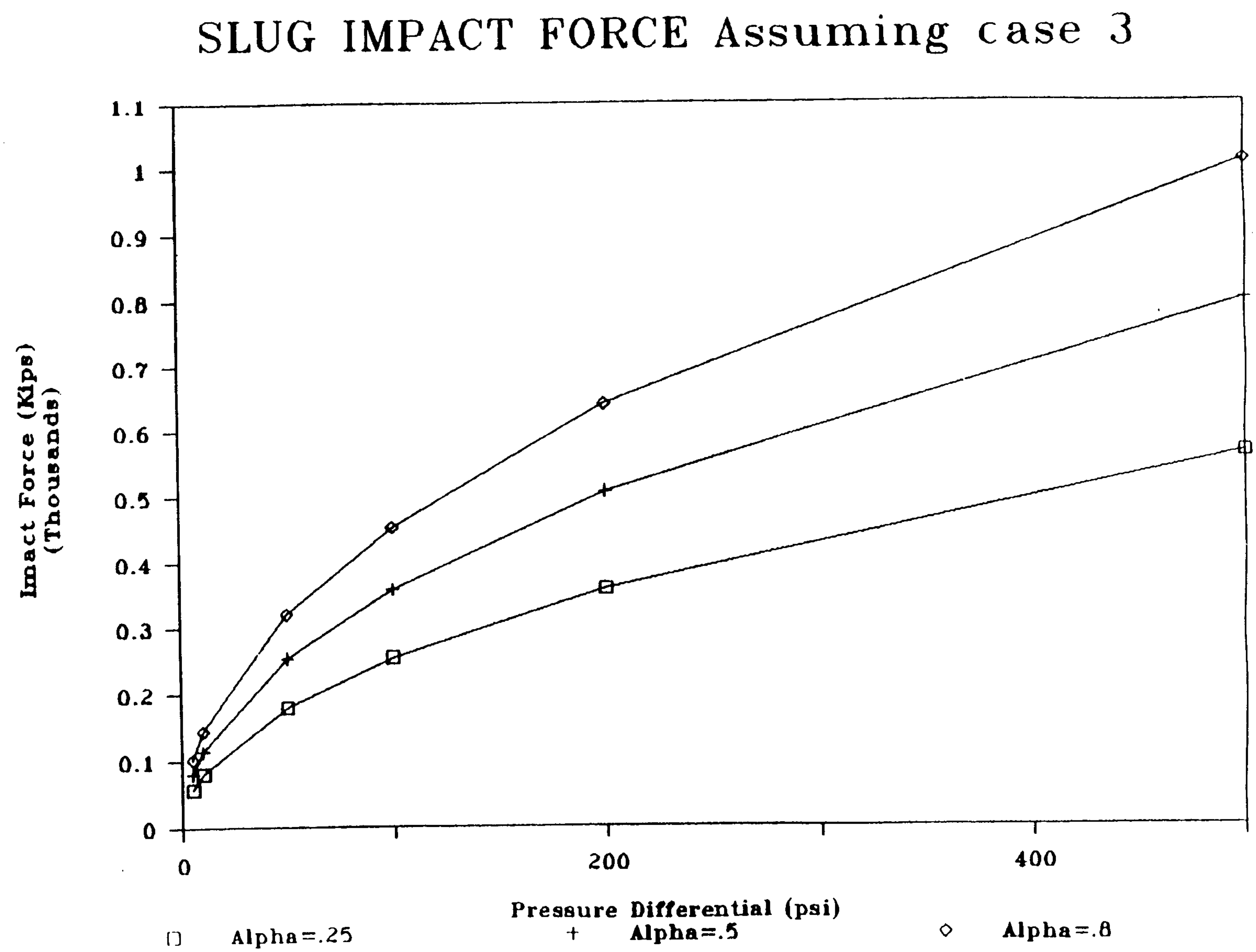


Figure 11-7. Slug Impact Force Versus Pressure Differential Over the Slug

Section 12

MAIN STEAM SYSTEM IN A BWR

SYSTEM FUNCTION

The main steam (MS) system transports the steam produced in the reactor pressure vessel through the containment structure to the main turbine generator and support auxiliaries. The portion of the piping from the reactor to the inboard isolation valve performs a safety function by preventing the uncontrolled release of steam to the surroundings and limiting the pressure transient on the reactor vessel during abnormal conditions.

Containment isolation can be obtained automatically through an isolation signal or manually by operator action.

The MS system is the primary means of conveying the reactor energy in the form of steam to the turbine-generators to produce power. The MS supply lines also deliver steam to the turbine bypass valves, steam jet air ejectors, pressure regulators, hydrogen recombiners, pressure averaging manifold, some of the pressure switches, various traps and drains, and the turbine gland sealing steam system.

SYSTEM CONFIGURATION, MODES OF OPERATION AND COMPONENT DATA

Configuration

Figure 12-1 shows a simplified schematic diagram of the Main Steam system. The system consists of four 20-in. main steam lines originating from the reactor and supplying steam to the high pressure turbine and the turbine bypass valves. Two isolation valves in each line allow the line to be isolated. Stop and control valves provide turbine trip and steam flow control capability. Exhaust steam from the H.P. turbine is fed into the low pressure turbines after passing through moisture separators. The L.P. turbines exhaust into the condenser. Steam can be routed directly to the main condenser in the event of a turbine trip through 10 of 10-in. bypass lines from the bypass valve chests. Provision is made to drain any condensate in the main steam lines during normal operation and also during startup.

Figure 12-2 shows the elevations for the main steam lines A and D which are very similar. Also shown is the vent line to the condenser and the reactor head vent line connecting main steam line A. Safety Relief valve discharge line from main steam line A is also shown. Figure 12-3 shows the elevation diagram for lines B and C. The bypass lines (and their elevations) from bypass valve chests A and B are shown in Figures 12-4 and 12-5, respectively. The piping inside the condenser is not included. For the purpose of the evaluations discussed in this report, the main steam system reviewed is limited to the portions shown in Figures 12-2 to 12-5 and does not include the extraction lines from the main turbine and other lines to low pressure turbine through the moisture separator reheaters.

Referring to Figure 12-1, the use of four main steam lines permit the testing of the of the MSIV's and the turbine stop valves without severely limiting load. Multiple steam lines also limit the differential pressure on reactor internals and reactor inventory loss during a steam line break accident, and permit high power operation with one steam line isolated.

The 20-in. lines branching from main steam lines A and B join at opposite ends of the A bypass valve chest as shown in Figure 12-4. These lines perform a pressure equalizing function for the A and B lines. Similarly, lines from the C and D main steam lines join the B valve chest as shown in Figure 12-5.

The average pressure in the four main steam lines is measured at the 2-in. pressure averaging manifold which connects to all four main steam lines through a 1/2-in. connection on each line. This arrangement, when coupled with the main steam pressure equalizing line (20-in. lines to the bypass valves), allows for the testing of the main stop valves at higher power levels without scramming the reactor because of high neutron flux and/or high steam line flow.

Figure 12-6 shows a schematic of the main steam lines drain system.

Main Steam System Operating Modes

Full power operation is the main mode in which steam flows through all 4 lines to the H.P. turbine. In the event of a turbine trip, the steam flow to the H.P. turbine is stopped and it flows through the bypass system to the main condenser.

Interfaces with Other Systems

a) Nuclear Boiler System: The nuclear boiler system provides steam supply for the main steam system. The instrumentation on this system also provides signals to actuate the main steam turbine stop valves and the Safety Relief Valves (SRV).

b) Containment System: The containment system provides the suppression pool water into which the safety relief valves discharge.

c) Nuclear Pressure Relief System: The nuclear pressure relief system depressurizes the reactor for small breaks through the safety relief valves to allow the emergency core cooling systems (low pressure coolant injection (LPCI) and core spray) to operate to protect the fuel barrier. It also prevents overpressurization of the main steam system that could lead to the failure of the reactor coolant pressure boundary.

d) Condenser Evacuation, Off Gas and Turbine Gland Seal Systems: The main steam system provides steam as the motive force for the steam jet air ejectors of the condenser evacuation system. It also provides relatively small amounts of steam to the off-gas and turbine gland seal systems.

e) Isolation Condenser System: The vent line from the isolation condenser steam supply line is connected to the main steam lines. The isolation condenser steam line pressure is therefore equalized to the main steam line pressure through the vent line.

Control Logic

Turbine trips may be initiated manually or automatically from part load or full load conditions.

Filling, Venting, and Draining

The main steam system is provided with a number of drains to remove condensate from the system. 2-in. drain lines from just upstream and downstream of the main steam inboard and outboard isolation valves remove moisture from these locations. These drains are equipped with motor operated valves that provide rapid draining of flooded steam lines and also equalize pressure to allow reopening of MSIV's at high pressure. Figure 12-6 schematically shows the main steam drain system.

During cold startup, the main steam eductor system can be used to remove the condensate from the main steam lines at the MSIV's. This is accomplished by first opening drain header stop valves MS-5 and MS-6. The master steam drain valve to condenser (MS-8) is then opened followed by the bypass drain valve to startup eductor. With MS-62 (drain trap bypass stop valve) and MS-63 (drain inlet stop valve to eductor) open, the eductor flow is started which starts draining the condensate. The valves MS-7 and MS-1 (MSIV's inside containment) are then opened. After verifying that the main steam turbine bypass valves are closed, the MSIVs outside the drywell are opened. Note that the lowest point in the 20-in. main steam line is the MSIV location (see Figures 12-2 and 12-3). The main condensate pumps provide the motive force to the eductor which pulls the condensate from the main steam line and discharges it to the B main condenser.

When the steam lines are drained, the eductor system is secured. During normal operation, any blockage of the main steam drains system in any steam line will result in an alarm in the control panel should the condensate level exceed the HI set point. This alarm level is 9 in. below the steam line. The operator is required to open the trap bypass valve to clear the condensate and hence the high level alarm. He should notify higher supervision if alarm persists.

Drain lines are also provided in the main steam bypass lines to the bypass valve chest through a drip leg arrangement. These again drain to the main condenser.

The steam line between the control valve and the H.P. turbine also is provided with 1-in. drain line.

The procedure (to be repeated approximately every 8 hours) for draining the main steam line with its isolation valves closed while the other three times are at rated flow is summarized below:

- Close the MS drain stop valves MS-78 for the three lines at rated flow
- Check open MS-78 on the idle MS line and valve MS-7
- Open MS-8 for approximately 5 minutes
- After 5 minutes, close MS-8 and check open MS-7
- Close MS-78 for the idle MS line and open the ones on the lines at rated flow
- Return the valves to their normal line-up when the idle MS line is brought back to service

During normal operation a path is open (2-in. line) from the reactor vessel head to the "A" main steam line to provide venting of non-condensable gases that accumulate above the level of the steam line nozzles.

Component Data

Table 12-1 gives the main design parameters for the main steam supply system. Component data for major valves in the system are tabulated on Table 12-2.

WATER HAMMER EXPERIENCE

In the 1970s a significant number of water hammer events were reported in LWR power plants (1), (2), and (3). Since 1978, the NRC has sponsored studies to evaluate the causes and recommend corrective measures to prevent or mitigate water hammer damage. (2) and (3) reviewed the above issues in detail. In all the past events, the occurrence of water hammer was mostly reported based on observed damage. Not many of water hammer events were actually witnessed. Since 1982 more events have been reported.

Each event was analyzed in the Task 2 Root Cause Report (4) to determine the areas of each system which are prone to water hammer, the specific water hammer mechanism, and root cause. The remedial actions taken by the utility to preclude future occurrence of a similar water hammer were described. Appendices A and B of (4) presented the BWR and PWR utility water hammer databases and Appendix C therein listed the utility plant codes used. Areas prone to water hammer were identified in typical schematics of each system discussed.

Two events which have occurred in BWR main steam systems are described below:

WATER HAMMER EVENT 1: STOP VALVE CLOSURE ON A TURBINE TRIP

Event Description

This event occurred during planned tests carried out under the power ascension of the plant and hence reasonable account of the event was available. Briefly the plant was under steady operation at a power level of 50 percent. The reactor pressure was 990 psig and the steam flow was 4.5 million lb/hr. The test was initiated by the push button turbine trip. In addition to the normal transient, the inside drywell main steam isolation valve on the D line went shut at approximately 5-7 s into the transient.

Several occurrences that are not of direct impact on the main steam system include, cleanup system isolation about 10-15 s into the event due to low water level in the vessel, subsequent trip of reactor feed pump 1B when the level reached above normal level set point, the recirc pumps were set back manually to minimum, the cleanup system was reopened to establish a drain path to the condenser to get the vessel level down.

At four minutes into the event, the operator concluded that nothing happened that would cause the main steam isolation to close.

The operator verified turbine coast down and lowered the (Mechanical Pressure Regulator) MPR to approximately 20 psi above reactor pressure. Reactor pressure came to the MPR and then the bypass valves opened rapidly. The resulting steam flow gave a "high steam flow" and an isolation valve closure to the 7 main steam valves that were still open. An additional scram signal was generated 7 minutes into the transient with the reactor pressure about 600 psig. The operator verified the cause of the isolation signal. He then opened the inboard and outboard drain valves and the return to steam line valve. Steam line pressure then was 250 psig with reactor pressure 808 psig.

Approximately one minute later, the operator opened the outboard main steam isolation valves.

At 9-10 minutes into the transient with the reactor pressure 818 psig and steam line pressure 600 psig, he opened the inboard steam isolation valves in order to reset the scram.

The scram was successfully reset. As the recovery seemed over at that point, it was contemplated that a cooldown should be initiated. One bypass valve was to be opened 10 percent. However, in opening the bypass the operator watched bypass opening jack position rather than the bypass position. This resulted in one full bypass opening and the second to open. This resulted in turn into a third scram which was on Low level.

The main steam lines were deflected excessively as a result of Event 1. Inspection of the steam lines indicated that the deflection was 12 to 18 in. in the north to south direction and 9 to 12 in. in the east west direction (see Figure 12-7). The anchor beam was totally destroyed. There were other problems associated with this event such as the closure of a MSIV due to component failure, malfunction of the main steam pressure control system. This rapid valve operation event is an anticipated event and the piping supports in this system were not designed for loads from such event. The main steam support system has been modified since this event to accommodate the loads due to rapid valve operation.

During this event the main steam pressure control system and the turbine bypass valves did not perform properly. The response of the mechanical pressure regulator and remote bypass valve jacking system lead to excessive bypass valves opening and too rapid depressurization of the reactor.

Mechanisms Responsible for Event

This event did not involve any of the severe water hammer mechanisms. The dynamic loads resulting into the damage noted above are associated with steam flow interruption due to valve closure. This is referred to generally as steam hammer. Turbine stop valve closure is usually considered in the design of the main system as part of the loads under normal transients. Turbine stop valve

closure should be an anticipated transient, however, since the original design of the system did not consider its loads, the problem was encountered.

Analysis of Root Causes

As noted above the sequence of occurrences that took place during this event did not involve any of the severe water hammer mechanisms. Specifically, the transient does not involve steam propelled water slug (Mechanism 5). This mechanism is the commonly encountered one in severe transients occurring in steam systems. Thus, at the outset of this root cause analysis, the event only involves "normal steam hammer."

The design of the main steam system piping supports did not take into account the turbine stop valve closure. To get an idea about the magnitudes of the dynamic forces associated with turbine stop valve closure.

Assuming the initial flow prior to turbine trip was 4.5 million lb/hr and equally distributed between the four leads to the turbine, together with the initial steady pressure of 990 psig, the calculated velocity in each of the 20-in. lines is about 65 ft/s. If the flow at each turbine stop valve is stopped instantaneously, then the pressure rise and the force associated with that pressure rise may be calculated using Joukowsky's law. Assuming a pressure wave speed of 1100 ft/s and a steam density of 2.2 lb/ft^3, a dynamic pressure increase of 34 psi is calculated. In reality, the stop valve effective closure time would be 30 to 60 ms. Thus, the dynamic load that a pipe segment would have seen would be a fraction of the total calculated. This fraction would depend also on the segment length. For illustration purposes, assume a stop valve closure time of 30 ms and pipe segments of 20-in. pipe, of lengths 20 ft and 40 ft, respectively. The first segment would see an imbalance force of about 6.5 kips and the second segment would encounter an imbalance of 10.7 kips. The pipe support system must not only be able to take these loads, but also should be capable of withstanding the larger loads associated with the 100 percent power turbine trip with the velocity in each lead being approximately 110 ft/s rather than the 65 ft/s that prevailed prior to the event.

From the description of the event, it is interesting to note that the spurious closure of the D isolation valve might have been the cause of the pressure wave that yielded the dynamic force resulting in the damage. This is not likely since the damage was not concentrated in line D and because isolation valve closure is generally of 3 s, (though under a spurious closure with a failure in the operator, the effective closure time may be much less).

Another point that is worth noting is that the closure of the line D isolation valve caused the flows to the other loads to be relatively large hence when the other isolation valves closed pressure waves were generated. Again those would have been of smaller magnitudes compared to those associated with the turbine stop valve closure.

The main cause for the damage occurring during event 1 is that the supports for the main steam lines were not designed for the anticipated transient. Other complications arose during the noted event due to the closure of one of the main steam isolation valves.

Special tests performed after the event indicated that the bypass valve operation was erratic. One of the reasons for this behavior was traced to the bypass valve relay pilot valve. This was an experimental non-case hardened valve and it had scored. This caused binding of the valve which probably resulted in the observed operation of 5 bypass valves opening at once instead of in sequence. The pilot valve was replaced with a case hardened valve.

Water Hammer Root Causes

Turbine stop valve closure was not factored in the design.

Corrective Measures

Additional supports were added allowing for the expected worst conditions of stove valve closure from 100 percent power.

The component that failed in the pilot valve of the main steam isolation valve that closed was replaced.

As for the bypass valves, these changes were made: a) a torn rubber flapper valve was removed in the hydraulic dampening device and the damping achieved by alternative methods and b) the bypass relay valve setting was changed to make the valve operate outside an internal dash pot region. With these changes, the bypass valves operated satisfactorily.

WATER HAMMER EVENT 2: STEAM BYPASS VALVE LIFT FOLLOWING TURBINE TRIP WITH A WATER SLUG IN THE LINE

Event Description

Unlike Event 1, no record is available on any observations during Event 2. Only what is known is what was discovered in inspections of the condenser nozzles. The failures noted below may have occurred due to a single event or due to several transients. This event was uncovered after the plant has been operating commercially for several years. The steam bypass header and cap at the main condenser failed. This was discovered and was attributed to impact loads due to water slug accelerated by steam flowing when the bypass valve opened following a turbine trip.

Mechanisms Responsible for the Event

Steam-propelled water slug (Mechanism 5).

Analysis of Root Cause

Though the details of the piping and the steam bypass line nozzles inside the condenser were not available, if one assumes that due to condensate collection with poor drainage (might have been due to plugging of drain holes with dirt over time), one may calculate the slug impact force. This can be accomplished using similar procedures to those utilized in Section 11.

Assuming situation "a" of Figure 11-5 (see Section 11) and a water slug density 60 lb/ft^3, a pressure wave speed of propagation 4000 ft/s and a pipe diameter of 8 in., a dynamic load of the order shown in Figure 12-8 is calculated, depending on the pressure differential acting on the slug. These loads are excessive for the cap.

Corrective Measures

The existing drain holes in the header were enlarged and additional holes added since the incident. This would permit adequate draining and prevent condensate accumulation thereby preventing water hammer due to this cause.

SYSTEM EVALUATION

Normal Transients

a) Turbine Stop Valve (TSV) Closure

During normal operation the most severe normal transient is the main steam turbine stop valve (TSV) closure. This valve is required to close very fast in order to perform its intended function of quick interruption of main steam flow to the H.P. turbine. Therefore, the piping support system must accommodate the loads generated as a result of this transient.

The damage caused during the startup of plant reviewed was because the piping support structure was not designed to sufficiently accommodate the TSV closure loads. The support damage was in the steam tunnel region. Since this incident the pipe supports in the main steam piping from the reactor to the H.P. turbine have been modified to accommodate the calculated TSV closure loads.

As per discussions with the plant engineering and operations personnel, a relatively recent transient caused by the stop valves closing from 100 percent power followed by the bypass valves opening resulted in the shearing off of the anchor bolts in the A and B steam lines near the steam tunnel. These supports were changed in 1982/1984 to rigid supports as part of the NRC IE Bulletin 79-14 (5). The transient that caused this recent damage is believed to the first trip from 100 percent power after the support modification.

b) Other Normal Transients

The closure of the main steam control valve and the MSIV also subjects the main steam piping to "steam hammer" loads but these are relatively smaller in general as compared to those due to TSV closure. The TSV closure time for the plant reviewed is about 0.09 s and that for the MSIV is 3 to 5 s.

The main steam bypass piping is subjected to steam hammer loads whenever the bypass valves are opened. These valves are also relatively fast acting and the loads generated must be accommodated by design. For the plant reviewed the opening time of the bypass valves is 0.15 s.

The safety relief valve discharge lines see fluid transient loads when the SRV is actuated. This line has the exit portion submerged in water before the SRV's open and, therefore, that portion experiences large loads when the water slug is expelled. The loads on this line must also be accommodated by design.

The transients generated by the TSV, CV, MSIV, SRV or bypass valves actuation are called "anticipated transients."

Severe Transients

As discussed in the previous section on water hammer experiences, the most common "unanticipated" severe transients in the main steam system occur when the steam lines are not properly drained or warmed before the steam flow is initiated. This would lead to steam propelled water slugs at high velocities and the generation of very high loads on system piping whenever these slugs pass by bends or decelerate/stop at pipe cross sectional reductions or valves.

For the plant evaluated, the main steam system piping was reviewed and it appears that the piping is adequately sloped. Data on the line slope per unit length of piping was not readily available. However discussions with plant engineering and operations personnel indicated that there are currently no water slug problems in the main steam line. In the past there was one problem which will be discussed later in this section. The reactor vessel grows vertically up about 2.3 in. upon heat up and this should help slope the line from the reactor to the MSIV's. Figures 12-2 and 12-3 show that the lowest point in the main steam piping from the reactor to the H.P. turbine is on the horizontal run containing the two MSIV's.

Drains are provided (see Figure 12-6) at this point. These drains are equipped with motor operated valves that provide rapid draining of flooded steam lines and are also designed to be used to equalize the pressures in the main steam line upstream and downstream of the MSIV's. During start up these drains are used with a condensate pump driven eductor system to remove the condensate from the main steam lines. Between the outboard MSIV and the stop valve, the lowest point in the lines to the bypass valve chest are also provided with a continuous drain through a drip leg system. There is provision to drain the stop/control valve above seat as required. The piping from the control valve to the H.P. turbine again has a low point drain. Therefore if the drain system operates properly, the likelihood of water slug formation and movement in the main steam line from the reactor to the H.P. turbine is small.

In the original design this plant did not have drains just before and after the MSIV. During the early part of plant coming into service, an incident occurred in which the MSIV's were opened without equalizing the pressure between the upstream and downstream of MSIV's and draining condensate buildup in the piping at this low elevation. The steam propelled water slug travelled in the piping and caused pipe support damage. This problem was fixed by installing the 2-in. drain lines as shown in Figures 12-2 and 12-3.

Figures 12-5 and 12-5 show the elevation diagrams for the bypass lines from the main steam bypass valve chest to the main condenser. Data on the sloping of these lines is not readily available but as per discussions with plant personnel, these lines should be adequately sloped. They generally slope to the condenser. One of the water hammer events at this plant occurred in the bypass piping inside the main condenser. Discussions with the maintenance personnel of this plant indicated that the end caps of the main steam bypass line spargers in the condenser used to blow off.

The thickness of these end cap plates have been increased and these damages have not recurred since. The details inside condenser are required to review this part of the system carefully. These were not available. Of particular interest in the piping are the flow orifices near the condenser in this line. If these are multistage orifices, then there is a potential for water accumulation inside the orifice if the drain holes connecting the various stages get blocked. This accumulated water could cause damage to the bypass pipe spargers.

Prevention, Mitigation, and Accommodation

As discussed in Section 5.1, the loads due to TSV, CV, MSIV and bypass valve actuation must be accommodated by design since the transients cannot be mitigated or prevented. The mechanisms that cause in the above mentioned transients are well known and the calculational procedures (which are generally computer analyses) are well established.

Water hammer caused by water slugs are generally very severe. Therefore, these should be prevented and not mitigated. This is possible by making sure that the main steam system is drained before system startup and during operation. It appears that at the plant reviewed detailed attention had been paid to these considerations.

Other Observations

During the TSV closure event when the plant was starting up, there were failures of MSIV and bypass valves. Although these in themselves did not result in water hammer, some of the past events on other plants (see Section 4) did have water hammer problems due to the improper function of MSIV's and bypass valves.

The main steam lines at this plant do not appear to have a large header to equalize pressure between the four lines. Line A and B are headered through the bypass line. Similarly lines C and D are headered. This means that if line A is isolated, unless the power is reduced, line B will receive more than the maximum flow unless the power level is reduced. If there was an equalizing header that equalized all four lines, then the power reduction required to keep the flow from exceeding the maximum is smaller. As per discussions with the plant operations personnel, closing an MSIV completely with the plant at 75 percent power leads to flow exceeding 120 percent in another steam line which is the maximum allowed flow.

Therefore, these tests are now performed by bringing the plant down to 65 percent power. The turbine stop valve closure tests are performed with the plant at a maximum of 90 percent power.

REVIEW OF OPERATING, TESTING AND MAINTENANCE PROCEDURES

The operating procedures for the plant reviewed refer to details of placing a cold or hot steam line in service, placing the MSIV's in service, and bypassing the MSIV's Low-Low water level trip when group 1 isolation does or does not exist. Finally, the procedures discuss the draining of the main steam line with the MSIV closed in one of the steam lines. A review of these procedures and discussions with the plant operations personnel show that a lot of attention has been paid to the prevention of water hammer by carefully addressing the draining of the steam lines and equalizing of pressure across the MSIV's before a restart of the plant with the reactor pressurized. This is accomplished by operational procedures and precautions. The following excerpts from the station operating procedure precautions and limitation section addresses the system draining aspect:

Prior to opening the outer isolation valves MS-2A, 2B, 2C and 2D, or downstream drain header stop MS-7, drain the water out of the main steam header sections upstream of the inner isolation valves.

The pressure across the isolation valves will be equalized prior to opening during a restart with the reactor vessel pressurized.

If the steam line is not drained, the following alarm is indicated:

"STEAM LINE NOT DRAINED"

At the beginning of the section in the operation procedures that deals with the draining of steam line(s) with MSIV closed in one main steam line, the following "Note" is given:

This step is to be performed when it is necessary to operate with one MS line isolated while the remaining three MS lines are at rated flow. It will assure drainage of entrapped condensation in the idle loop.

This procedure must be performed for a period of approximately 5 minutes once per shift.

The testing requirements of the MSIV's are contained in the plant technical specifications for the plant reviewed. These valves must be exercised by partial closure and subsequent reopening at least once per month. With the reactor power less than 75 percent of rated, the MSIVs must be tripped (one at a time) at least once per quarter and their closure time verified. At least once per operating cycle, the operable MSIVs that are power operated and automatically initiated must be tested for simulated automatic initiation and closure times.

Discussions with the maintenance personnel indicated that the the MSIV's require significant maintenance work. This work is generally to fix seat problems but this is nothing unusual. The Miller air operators on these valves have not been changed. The drain traps in the main steam lines are mostly Armstrong high pressure traps and these require normal maintenance. The maintenance personnel do not report unusual degree of problems with these traps. In other plants drain traps have been very troublesome and have been replaced by other more reliable devices. It is prudent to regularly inspect and maintain the steam line drain system.

The inspection procedures contained in the In Service Inspection program were not examined in detailed.

The snubbers on this system are inspected regularly according to plant technical specification for inspection and testing, and the leaking ones are repaired as per the maintenance personnel.

STRENGTHS AND WEAKNESSES FOR WATER HAMMER PREVENTION

Strengths

The main steam system is provided with a number of drains to remove condensate from the system. 2-in. drain lines from just upstream and downstream of the main steam inboard and outboard isolation valves remove moisture from these locations. These drains are equipped with motor operated valves that provide rapid draining of flooded steam lines and also equalize pressure to allow reopening of MSIV's at high pressure. Figure 12-6 schematically shows the main steam drain system.

During cold startup, the main steam eductor system can be used to remove the condensate from the main steam lines at the MSIV's. This is accomplished by first opening drain header stop valves MS-5 and MS-6. The master steam drain valve to condenser (MS-8) is then opened followed by the bypass drain valve to startup eductor. With MS-62 (drain trap bypass stop valve) and MS-63 (drain inlet stop valve to eductor) open, the eductor flow is started which starts draining the condensate. The valves MS-7 and MS-1 (MSIV's inside containment) are then opened. After verifying that the main steam turbine bypass valves are closed, the MSIVs outside the drywell are opened. Note that the lowest point in the 20-in. main steam line is the MSIV location (see Figures 12-2 and 12-3). The main condensate pumps provide the motive force to the eductor which pulls the condensate from the main steam line and discharges it to the B main condenser. When the steam lines are drained, the eductor system is secured. During normal operation, any blockage of the main steam drains system in any steam line will result in an alarm in the control panel should the condensate level exceed the HI set point. This alarm level is 9 in. below the steam line.

The operator is required to open the trap bypass valve to clear the condensate and hence the high level alarm. He should notify higher supervision if alarm persists.

Drain lines are also provided in the main steam bypass lines to the bypass valve chest through a drip leg arrangement. These again drain to the main condenser. The steam line between the control valve and the H.P. turbine also is provided with 1-in. drain line.

Water hammer caused by water slugs are generally very severe. Therefore these should be prevented and not mitigated. This is possible by making sure that the main steam system is drained before system startup and during operation. It appears that detailed attention has been paid to these considerations.

<u>Weaknesses</u>

While the addition of supports to withstand steam hammer loads is desirable, if the added supports are too rigid, support damage may still be encountered.

REFERENCES

1. NUREG-0927 Revision 1, <u>Evaluation of Water Hammer Occurrence in Nuclear Power Plants</u>, 1984.

2. NUREG/CR-2781 QUAD-1-82-018 EFF-2203, <u>Evaluation of Water Hammer Events in Light Water Reactor Plants</u>, 1982.

3. NUREG/CR-2059 EGG-CAAD-5629, <u>Compilation of Data Concerning Known and Suspected Water Hammer Events in Nuclear Power Plants</u>, 1982.

4. Van Duyne, D. A., Yow, W., and Sabin, J. W., "Water Hammer Prevention, Mitigation, and Accommodation, Task 2 - Root Cause Analysis for Plant Water Hammer Experience," EPRI RP-2856-3, Task 2 Report, December 1989.

5. NRC IE Bulletin 79-14, "Seismic Analysis for As-Built Safety-Related Piping Systems," 1979.

Table 12-1

MAIN DESIGN PARAMETERS FOR THE MAIN STEAM SYSTEM

Valve wide open flow rate	8,140,000 Lbm/Hr
Number of Lines	4
Line Outside Diameter	20 in.
Design Pressure	1250 psig
Design Temperature	575 °F

Table 12-2

MS VALVE DATA

<u>Turbine Stop Valve</u> (Hydraulic)	
Valve closing time	0.09 s
Valve closing characteristics	Not Available
<u>Control Valve</u> (Hydraulic)	
Valve closing time	--
Valve closing characteristics	Not Available
<u>Isolation Valve (Gate) MS-3</u> (Air)	
Number of valves per line	2
Valve closing time	3-5 s
Valve opening time	3-5 s
Valve closing characteristics	Not Available
<u>Bypass Valves</u> (Hydraulic)	
Number of valves per chest	5
Valve opening time	0.15 s
Valve closing characteristics	Not Available
Valves opening sequence	
<u>Drain Valves</u> (Motor)	
MS-5 operating time, max	35 s
MS-6 operating time, max	35 s

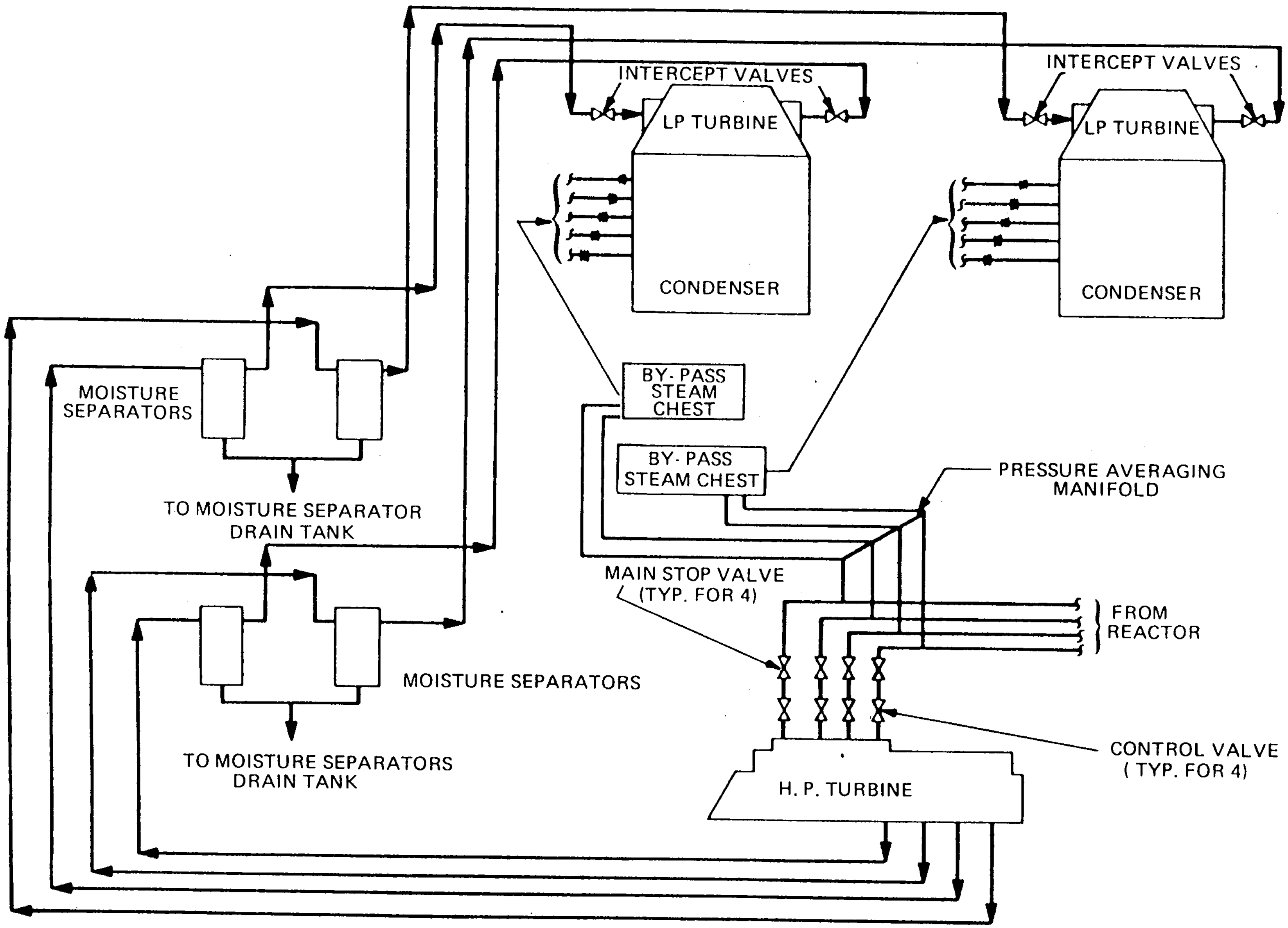


Figure 12-1. Main Steam System Flow Path

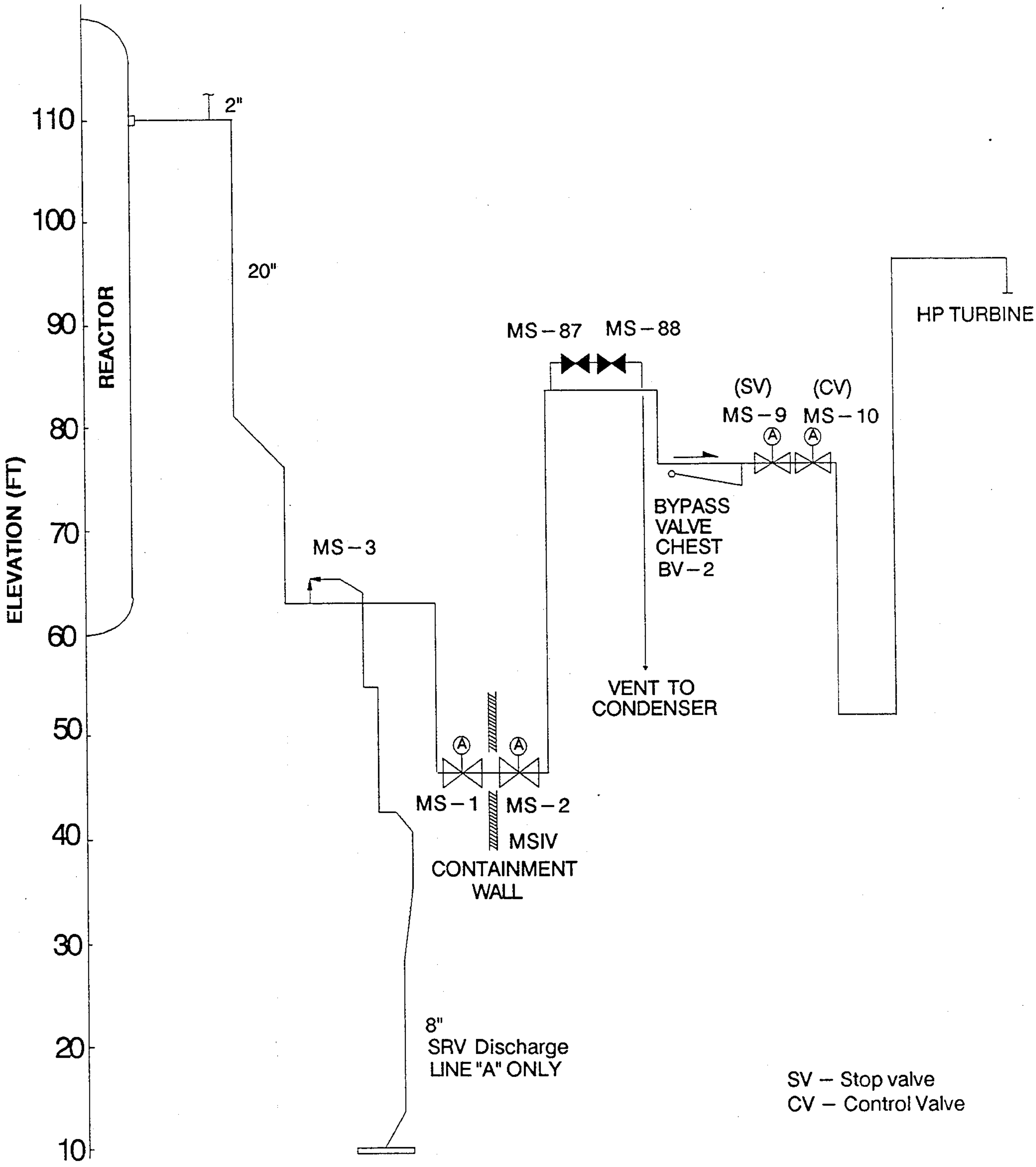


Figure 12-2. Elevation Diagram for Main Steam Lines A & D
(See Figure 12-6 for the Drain System Schematic)

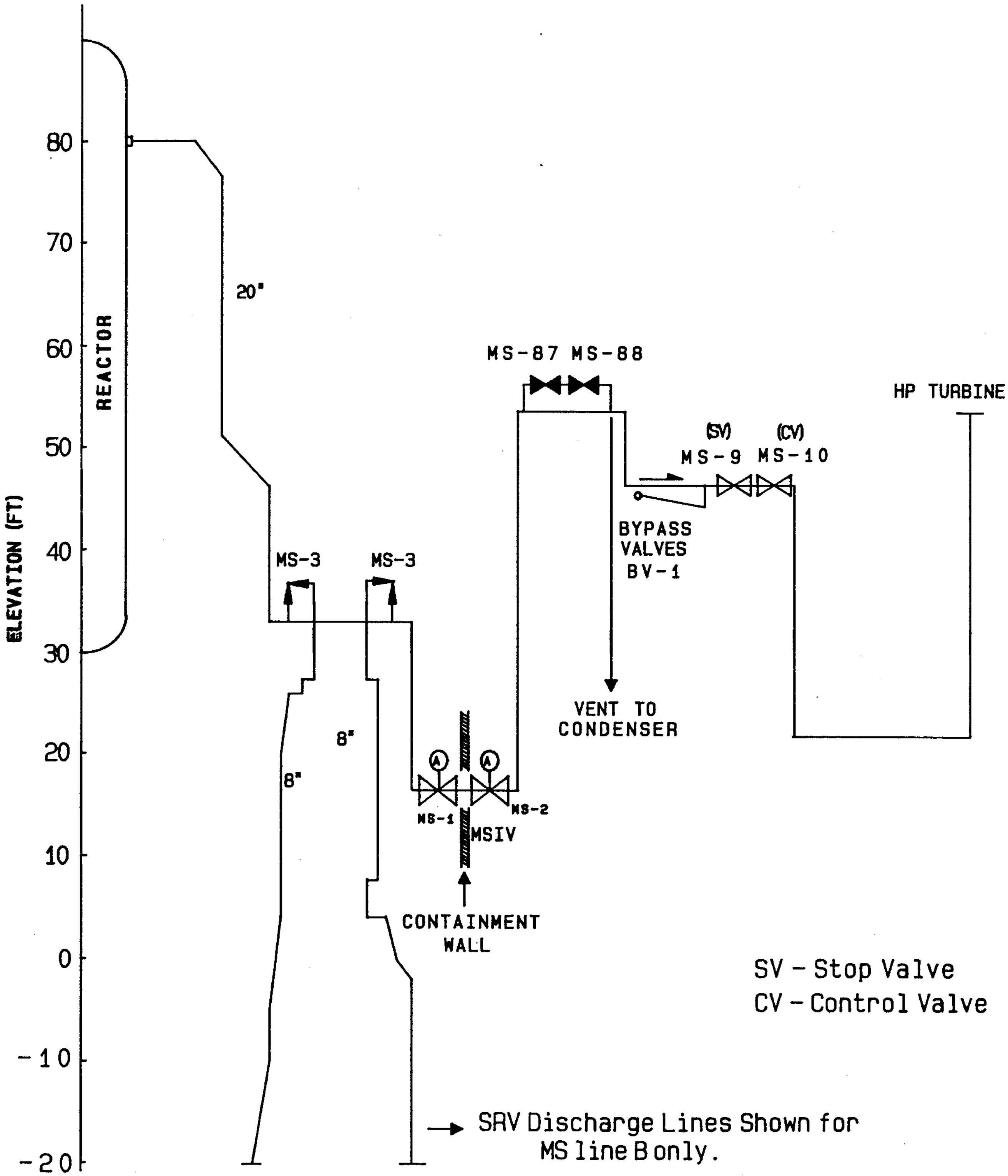


Figure 12-3. Elevation Diagram for Main Steam Lines B&C
(See Figure 12-6 for the Drain System Schematic)

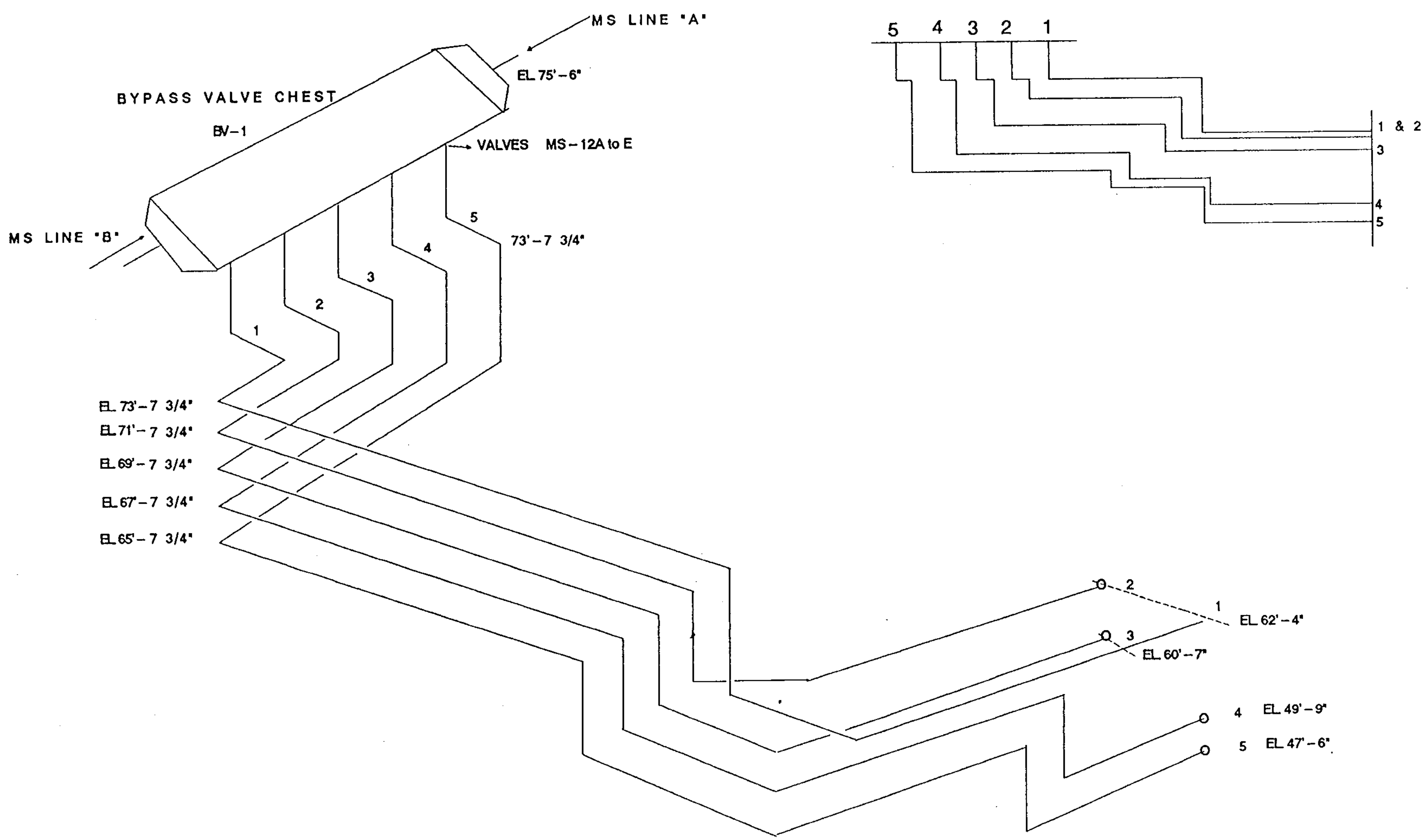


Figure 12-4. Elevation Diagram & Isometric of MS Bypass System from Valve Chest BV-1

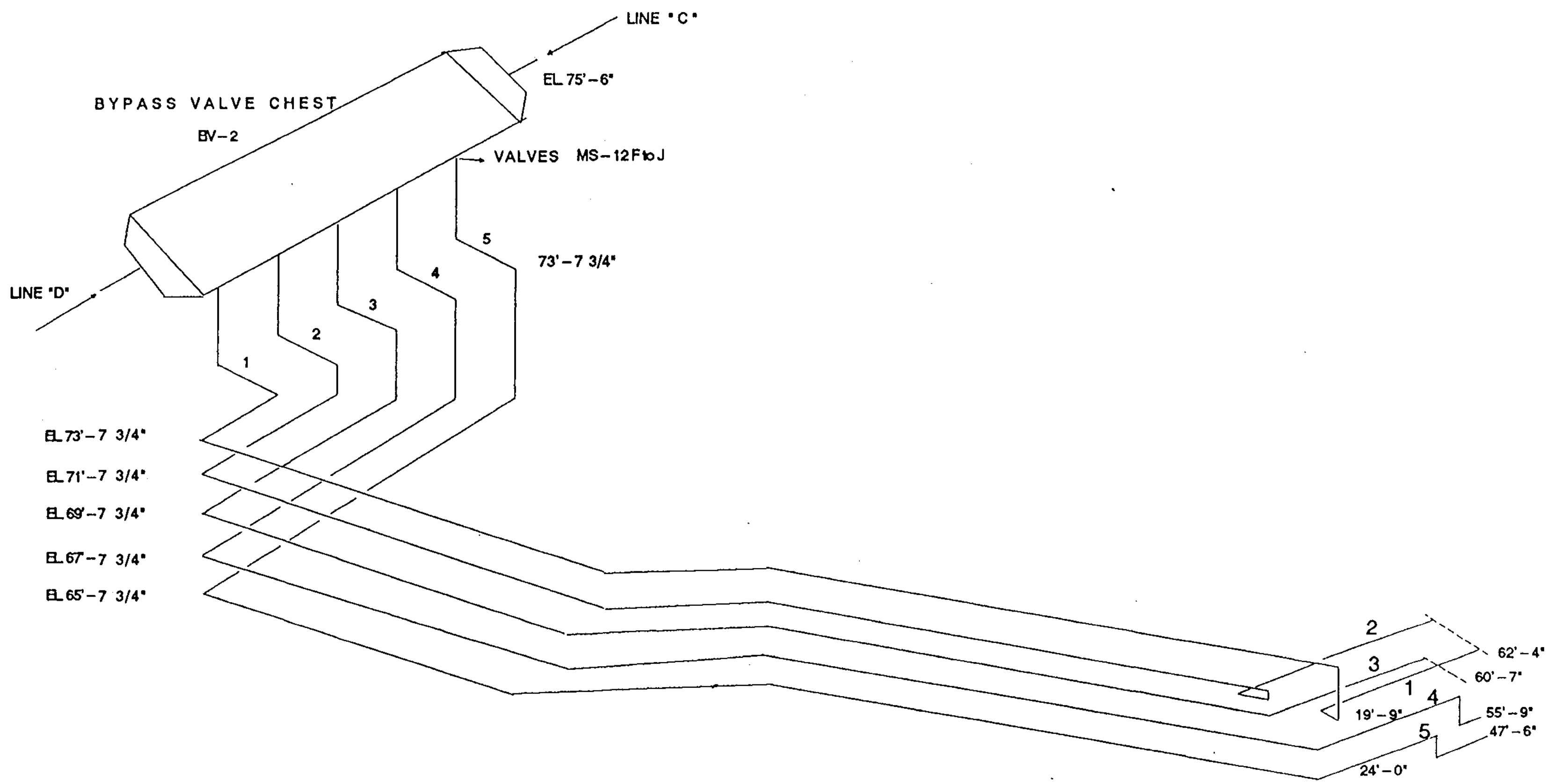


Figure 12-5. Elevation Diagram for Main Steam Bypass System from Bypass Valve Chest BV-2

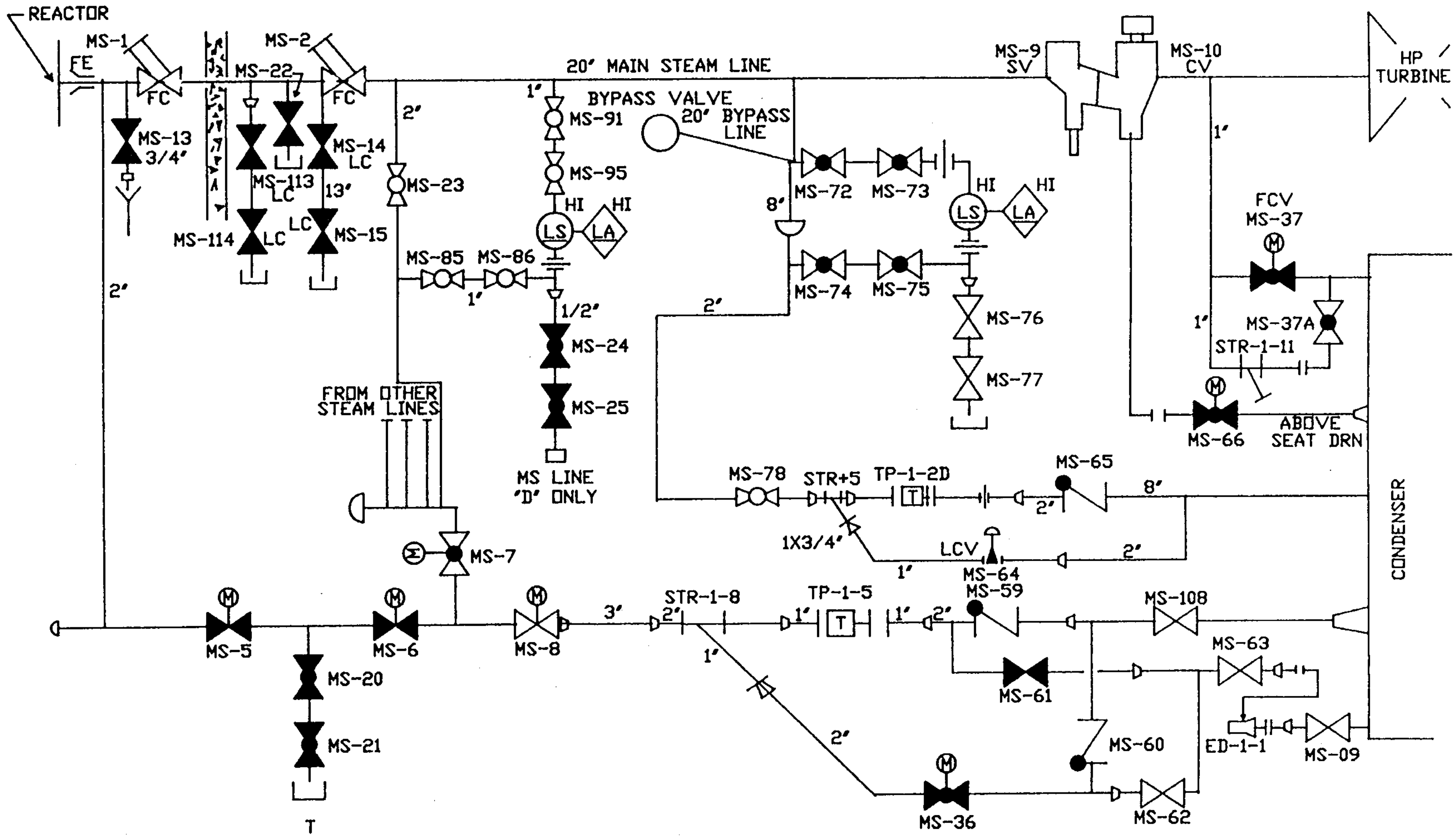


Figure 12-6. Schematic Diagram of the Main Steam Line Drain System

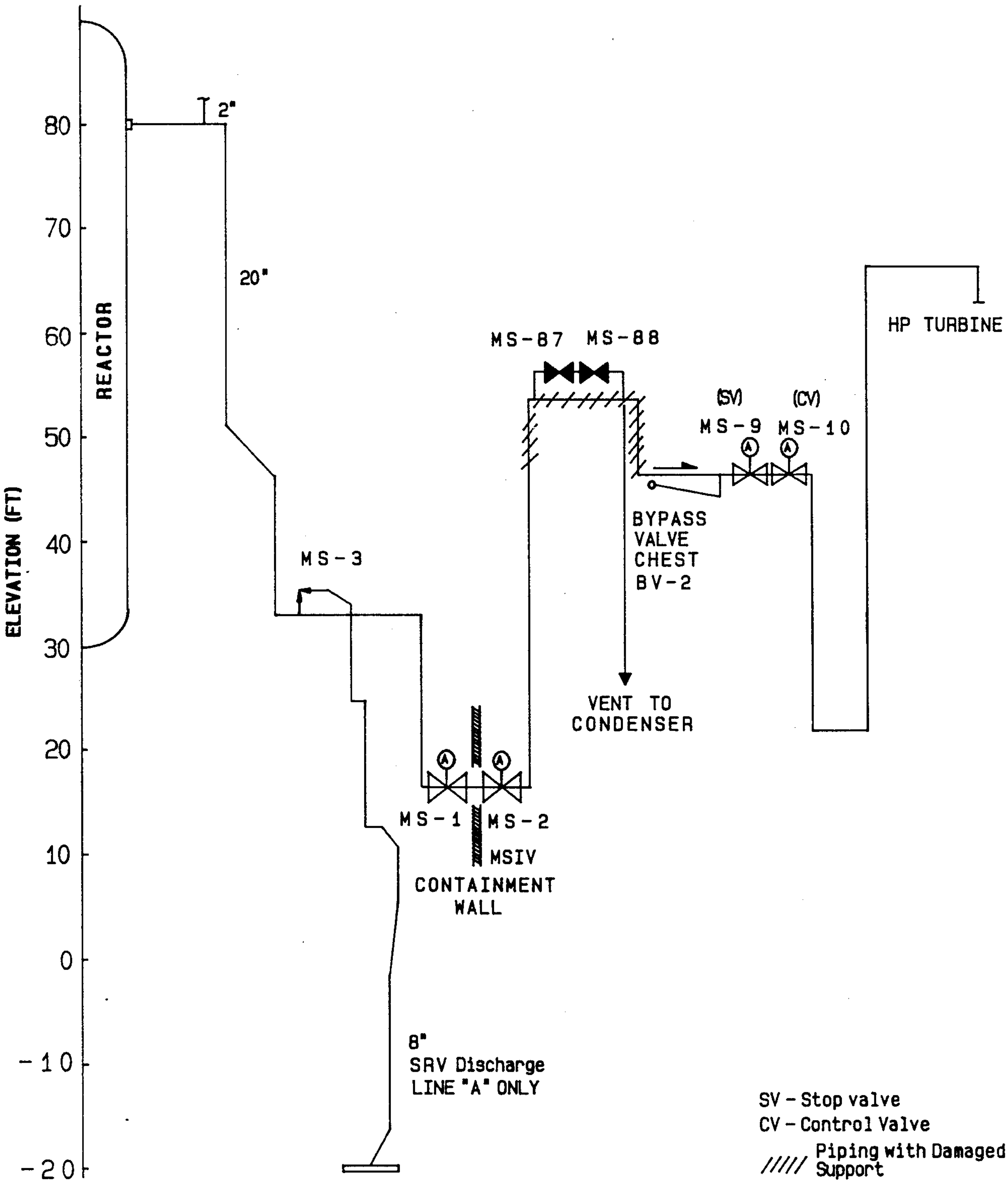


Figure 12-7. Main Steam Lines A & D Showing Support Damage Area

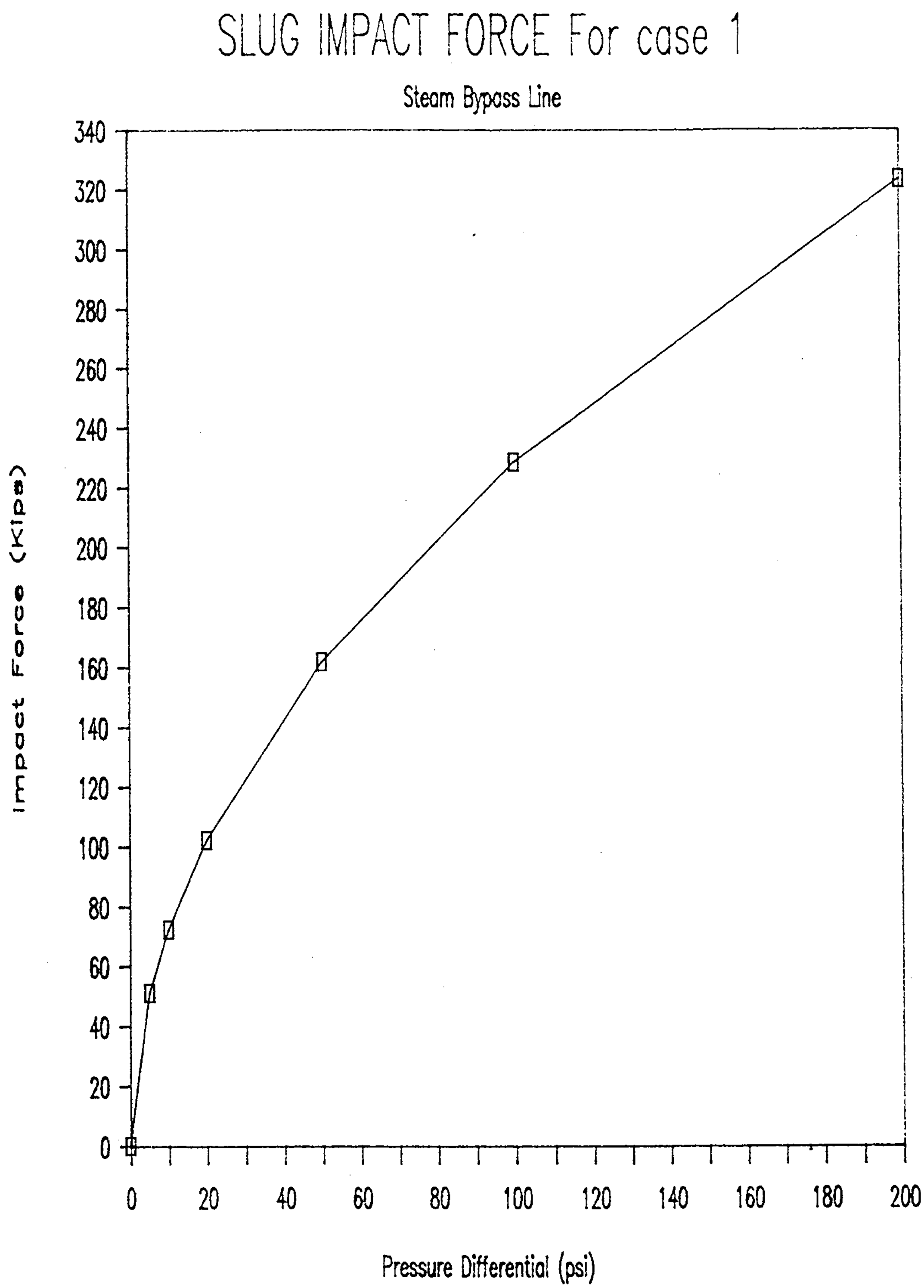


Figure 12-8. Slug Impact Force Versus Pressure Differential Over the Slug (For Situation A in Figure 11-5 and Case 1 in Table 11-1)

Section 13

SUMMARY OF TASKS 6 AND 7 RESULTS

Data collection and review of plant specific data for water hammer has been conducted for a BWR plant and several PWR plants. These plants were selected as representative of each category of nuclear reactor available in the U.S. nuclear power industry.

Water hammer events occurred in the condensate and feedwater system, feedwater heater drain system, steam generator blowdown system, auxiliary feedwater system, low pressure safety injection system and the residual heat removal system of several PWR plants have been reviewed. Similarly, the water hammer events occurred in the core spray system, low pressure coolant injection system, isolation condenser system, and main steam system of a BWR plant have been reviewed. System design and operating data associated with these events have been collected and analyzed for the root causes of the water hammers.

SUMMARY OF ROOT CAUSES

The summary of the review of the events in BWR and PWR plants conducted in this study are shown in Table 13-1. The root causes of the water hammer events are further summarized as follows:

Water Hammer Events Attributable to Design Aspects:

- Inadequate line size results in excessive velocity which may develop water hammer induced by water column separation and rejoining.
- Typical piping layout of feedwater heater drain dump line will cause accumulation of stagnant subcooled water upstream of the dump valve followed by saturated water. These conditions may lead to a low pressure discharge water hammer.
- Inadequate condensate draining capability in a steam supply line may develop water slug induced water hammer.
- Inadequate piping support system may not withstand normal operational transient loadings.

- Lack of a keep-full system and lack of void detection system in a core spray line may result in a water hammer induced by water column separation and subsequent rejoining during pump startup.

Water Hammer Events Attributable to Procedural Considerations:

- Inappropriate startup of an RHR pump when the suction water level in an RCS hot leg is excessively low causing air entrainment through the pump impeller, which result in water hammer induced by rapid closure of RHR pump recirculation flow control valve.

- Failure of the operating procedures to isolate feedwater flow into the reactor pressure vessel during a reactor trip, which results in a water hammer induced by water slugs entrapped in the isolation condenser steam supply line.

- Absence of clear operating procedures for placing a high pressure feedwater heater back into operation with the plant at power resulted in abnormal pressure differential and reverse flow in the normal cascading drain flow path which created high water level and operation of the emergency dump system causing a severe water hammer.

- Absence of a preventive procedure to avoid vapor pocket formation in the feedwater heater drains dump line to the condenser allowed a vapor pocket collapse transient after the adjacent isolation valve was manually operated.

Water Hammer Events Caused by Equipment Failure:

- Leaky isolation and check valves in a feedwater line resulting in a water hammer induced by steam and water counterflow in a horizontal pipe.

- The leaking of the feedwater line containment penetration nozzles results in exposure of the feedwater line to steam which causes a condensation induced water hammer.

- Failure of the stop check valve at an SI pump discharge header causes a water hammer induced by rapid closure of the stop check valve which stays open after a parallel pump starts until the flow through the check valve reaches a large reverse flow then slams shut.

- Leaky isolation valve in a letdown line or a core spray line resulting in a steam bubble to be trapped at the valve, which causes a water hammer when the pump subsequently starts and collapses the steam bubble.

- Failure of an RHR pump suction isolation valve actuator results in a water hammer induced by rapid valve closure.

- Leaky dump line isolation valve in the feedwater heater drain system allowed formation of a vapor pocket in piping near the condenser which collapsed when the adjacent isolation valve was manually operated.

RECOMMENDATIONS FOR PREVENTION OF WATER HAMMER

Based on the lessons learned from this investigation, the following recommendations are developed for improvements and prevention of water hammer:

Condensation Induced Water Hammer

- Avoid direct contact of steam with subcooled water in a horizontal or near horizontal pipe.
- Avoid disturbing water surface in a stratified steam and subcooled water environment.
- Slowly open an isolation valve, especially for a system where stagnant cold water coexists with hot water in the same line.
- Avoid opening an isolation valve adjacent to a steam or vapor pocket, or open it very slowly to relieve the steam or vapor pocket.
- The heater drain tank vent line for pressure equalization between the feedwater heater and the drain tank should be adequately sized for both steady state operation and transient conditions.
- Provide clear operating procedures for placing a high pressure feedwater heater back into operation with the plant at power without inadvertently actuating the emergency dump system.

Water Slug Induced Water Hammer

- Routine inspection of condensate removal systems to avoid accumulation of water slug in the steam line.
- Review steam supply line startup procedures to ensure proper warming of the steam line without causing excessive condensation.

Water Hammer due to Rapid Valve Actuation

- Routine inspection of check valves, especially those located at the pump discharge header, to ensure that the valve disc does not stick open.
- Use of a tilting disc check valve, instead of a swing check valve, in areas where sudden reverse flow is expected.
- Avoid using a stop check valve to serve the dual functions of flow isolation and non-return flow. Instead, use a gate valve and a tilting disc check valve in series.

Water Hammer due to Filling of a Voided Line

- Avoid starting a pump with a voided discharge line due to valve leakage or lack of keep-full system when the piping elevation is excessively higher than the suction water level.
- Use only slow or moderate valve closing speed to isolate a pipe where flow velocity is excessive.

Table 13-1

SUMMARY OF REVIEW OF WATER HAMMER EVENTS IN BWR AND PWR PLANTS

REACTOR	SYSTEM	EVENT DESCRIPTION	MECHANISM	ROOT CAUSES	CORRECTIVE MEASURES
PWR	FW	Vent and drain operation	2	Leaky isolation and check valves; faulty draining procedures	Revise draining procedures to wait until water cooled off
PWR	FW	Steam generator water hammer	2	Containment penetration nozzles leaking	Control AFW injection rate; monitor water chemistry for erosion-corrosion
PWR	FW	FW miniflow recirculation line	7	Inadequate FW recirculation line size	Increase FW recirculation line size
PWR	FWHD	Third point heater transient dump isolation valve operation	4	Trapping of cold water in a FW heater drain dump line followed by saturated water	Revise dump valve opening rate to be slower than 20 s to mitigate the transient
PWR	FWHD	First point heater transient dump line emergency control valve operation	4	Trapping of cold water in the dump line followed by saturated water	Operating procedures were changed to provide for placing a high pressure heater in service without inadvertently actuating the emergency dump system
PWR	FWHD	First point heater transient dump line isolation valve operation	3	Downstream emergency drain valve leaked to condenser creating a vapor pocket after manual isolation valve	Startup procedure was revised to fill drain pipe with lower temperature condensate to avoid flashing if leakage did occur
PWR	SGB	SG blowdown initiation after system isolation	4	Faulty startup procedures with a voided line	Revise startup procedures to refill the line prior to starting
PWR	AFW	Turbine-driven AFW pump start	5	Inadequate draining capability	Replace solenoid drain valves with orifices
PWR	LPSI	Pump startup during testing	6	Faulty stop check valve at pump discharge header	Change valve stem/disc material to stainless steel to improve deformation resistance

Table 13-1

SUMMARY OF REVIEW OF WATER HAMMER EVENTS IN BWR AND PWR PLANTS
(CONTINUED)

REACTOR	SYSTEM	EVENT DESCRIPTION	MECHANISM	ROOT CAUSES	CORRECTIVE MEASURES
PWR	RHR	Transient in letdown line upon flow initiation	3	Leaky isolation valve	Add a vent valve to bleed off steam bubbles; throttle pump valve during startup
PWR	RHR	Inadvertent closure of RHR pump suction valve	7	Failed valve actuator	Repair damaged pipe supports
PWR	RHR	Closure of RHR pump recirculation flow control valve	6	Vortexing due to excessively low suction water level in RCS hot leg	Maintain a minimum suction level and a maximum flow for RHR pump start permissibility
BWR	CS	Pump startup with a voided line	7	Lack of a keep-full system	Install a keep-full system
BWR	CS	Pump startup with steam in the line	3	Leaky core spray injection valve	Repair valve for leaktightness; enhance keep-full system
BWR	LPCI	Pump startup with a voided line	7	Leaky valves and keep-full system not operational	Redesign pipe supports for larger loads
BWR	IC	Water slugs in steam supply lines	5	Procedures failed to isolate FW resulting in excessive RPV level	Revise procedures for a quick trip of FW pumps during a reactor trip
BWR	MS	Stop valve closure on turbine trip	6	Inadequate system design for a normal transient	Modify and repair damaged pipe supports
BWR	MS	Steam bypass valve lift with a water slug in the line	5	Inadequate draining capability	Increase drain hole size

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