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Technical Assistance Related to ISA Issue No. 5

Reliance on Containment Overpressure for Ensuring Appropriate NPSH

Final Technical Evaluation Report

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Table of Contents

List of Figures

List of Tables

1.0 INTRODUCTION

This report documents work performed by Science and Engineering Associates, Inc. (SEA) for the U.S. Nuclear Regulatory Commission (NRC) under Contract No. NRC-04-97-036, Task No. 5, Modification No. 2, titled "Technical Assistance Related to ISA Issue No. 5". SEA was tasked to provide technical assistance to the NRC staff in their review of the criterion related to licensee reliance on containment over-pressure for ensuring appropriate net positive suction head (NPSH) for emergency core cooling and containment heat removal pumps.

1.1 Background

The NRC identified a safety-significant issue with generic implications that warrants NRC action to ensure that the issue is adequately addressed. The issue addresses the adequacy of the available NPSH for ECCS and containment heat removal pumps under all design-basis accident scenarios. The safety issue was identified as a result of recent inspection activities, licensee notifications, and licensee event reports (LER).

Concerns regarding potential inadequate NPSH include the following: changes of plant configuration, operating procedures, environmental conditions, or other parameters over the life of the plant; NPSH analysis not bounding all postulated events for sufficient time, or non-conservative or inconsistent analytical assumptions and methodologies. Some licensees must now take new or additional credit for containment overpressure to meet the NPSH requirements. The overpressure credited by licensees may be inconsistent with the plant's respective licensing basis because of changes in plant configuration and operating conditions, and/or errors in prior NPSH calculations.

To gather additional information, the NRC issued Generic Letter (GL) 97-04, titled, "Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps," [1] on October 7, 1997, requesting licensees to provide current information regarding NPSH analyses for the ECCS and containment heat removal pumps. The NRC has received licensee responses to GL 97-04.

1.2 Work Scope

SEA was contracted by NRC to provide technical assistance to the staff in reviewing and clarifying the staff's criteria relative to relying on containment overpressure for ensuring appropriate NPSH for ECC and containment heat removal pumps. The statement of work (SOW) was divided into the following three subtasks:

1. The first subtask (Subtask 5.1) was to review NPSH guidance provided in Regulatory Guide (RG) 1.1 [2], RG 1.82 [3], Rev. 2, and Standard Review Plan (SRP) 6.2.2, Rev. 4 [4]. The purpose of the review was to determine where further clarification is needed based on insights gained from activities related to the BWR strainer blockage issue and other recent Generic Letters and Information Notices for the purpose of identifying a need for additional clarification or change. This subtask also included an evaluation of the pros and cons of sustaining multiple regulatory guidance documents versus subsuming such guidance into a singular RG or SRP dealing with the calculation of NPSH margins.

2. The second subtask (expanded scope of Subtask 5.1 per task modification number 2) was to review NPSH calculations that have been performed for a selected number of BWRs and PWRs utilizing FSAR and IPE information currently available at SEA. Also included in this subtask was the development of a calculational overview and methodology that incorporates controlling physical phenomena and post-LOCA time-dependent effects based on current analytical and experimental evidence and computational tools judged best for such analyses.

3. The third subtask (Subtask 5.2) was to review comments received in response to GL 97-04 to determine the need for changes to current regulatory guidance and to update positions developed in the previous two subtasks.

Prior to task modification no. 2, the task contained an additional subtask, Subtask 5.3. Subtask 5.3 was withdrawn per modification no. 2.

The scope of work for this study was decomposed into the following five steps.

Regulatory Guidance Existing regulatory guidance was reviewed to determine both its content and the need for further clarification.

NPSH Methodology A comprehensive calculational methodology was developed for NPSH and overpressure analyses based on existing information and guidance. The relative importance and sensitivity of applicable physical phenomena and calculational parameters were also considered.

Importance of Adequate NPSH Margin A screening level PRA evaluation was performed to estimate the importance of losing adequate NPSH margin to the risk of damaging the reactor core and to estimate the importance of considering other accident scenarios besides the design basis LOCAs.

Detailed Review The NPSH analysis for one BWR plant was reviewed in detail to further illustrate the importance of phenomena and calculational parameters. Time-dependent containment response calculations were performed to illustrate the process of determining minimum available containment pressure. Limited resources precluded performing a similar review for a PWR plant; however, the basic conclusions are applicable to both designs.

Overview of Industry NPSH Analyses The licensee responses to GL 97-04 were reviewed to determine trends and to gain general insights into existing industry NPSH analyses.

1.3 Report Content

Each section of the report discusses one aspect of the study.

- Section 2 discusses the review of existing regulatory guidance, the need for further clarification, and the evaluation of subsuming (or not) regulatory guidance into a single guide.
- Section 3 provides an overview of the calculational methodology used in NPSH analyses.
- Section 4 provides a methodology for evaluating important accident scenarios for NPSH analysis from a PRA prospective along with a screening level evaluation to illustrate the process.
- Section 5 contains a detailed calculational review of the NPSH analyses for the Duane Arnold plant including time-dependent analyses illustrating a procedure for determining available overpressure.
- Section 6 contains the review comments for the overall review of licensee responses to GL 97-04.
- Section 7 contains a summary of the study's conclusion and recommendations.

2.0 REVIEW OF EXISTING REGULATORY GUIDANCE ON NPSH ANALYSES

NRC guidance documents pertinent to NPSH analysis were reviewed to determine where further clarification is needed based on insights gained from activities related to the BWR strainer blockage issue and other recent Generic Letters and Information Notices for the purpose of identifying a need for additional clarification or change. The documents reviewed included:

- Regulatory Guide 1.1
- Regulatory Guide 1.82, Rev. 2
- Standard Review Plan 6.2.2, Rev. 4
- Standard Review Plan 6.2.1.5, Rev.4
- 10 CFR Part 50, Appendix K [5]

The pros and cons of sustaining multiple regulatory documents versus subsuming such guidance into a singular RG or SRP dealing with the calculation of NPSH margins were also evaluated.

2.1 Applicable Regulatory Guidance

The pertinent features of these documents applicable to NPSH analyses are now described.

Regulatory Guide 1.1 Regulatory guidance for ensuring a net positive suction head for emergency core cooling and containment heat removal system pumps is provided in RG 1.1. The stated regulatory position is:

- Emergency Core Cooling and Containment Heat Removal Systems should be designed such that adequate net positive suction head (NPSH) is provided to system pumps assuming maximum expected temperatures of pumped fluids and no increase in the containment pressure from that present prior to postulated loss of coolant accidents.

RG 1.1 discussed the importance of the proper performance of emergency core cooling and containment heat removal systems being independent of calculated increases in containment pressure caused by postulated LOCAs in order to assure reliable operation under a variety of possible accident conditions. An example provided in the RG was:

- If proper operation of the ECCS depends upon maintaining containment pressure above a specified minimum, then too low an internal pressure (resulting from impaired containment integrity or operation of containment heat removal systems) could significantly affect the ability of this system to accomplish its safety functions by causing pump cavitation.

Regulatory Guide 1.82, Rev 2 Regulatory guidance for ensuring water sources for long-term recirculation cooling following a LOCA is provided in RG 1.82. The guide describes methods acceptable to the NRC staff for implementing applicable General Design Criterion (GDC) requirements with respect to the sumps and suppression pools performing the functions of water sources for emergency core cooling, containment heat removal, or containment atmosphere clean up. The guide also includes guidelines for evaluating the adequacy of the availability of the sump and suppression pool for long-term recirculation cooling following a LOCA.

RG 1.82, Rev. 1 was revised to deal with all aspects of LOCA generated debris and its associated blockage of strainers and strainer head losses. Note that RG 1.1 was specifically invoked by RG 1.82, Rev. 2 for determining available NPSH in BWR plants but it was not invoked for PWR plants. RG 1.82 addresses debris from plant operations, at least for BWRs, but the foreign material exclusion (FME) was not specifically introduced into Rev. 2. Detailed technical guidance for the evaluation of strainer head loss is found in the documents referenced by RG 1.82, Rev. 2.

SRP 6.2.2, Rev 4 Additional regulatory guidance is found in Section 6.2.2 of the Standard Review Plan dealing with containment heat removal systems. It states:

- The NPSH analysis will be acceptable if it is done in accordance to the guidance in RG 1.82, Rev. 1, and RG 1.1, i.e., is based on maximum expected temperature of the pumped fluid and with atmospheric pressure in the containment.

- For clarification, the analysis should be based on the assumption that the containment pressure equals the vapor pressure of the sump water. This ensures that credit is not taken for containment pressurization during the transient.

Furthermore, SRP 6.2.2 also addresses other important factors that should be taken into consideration. Examples include:

- Heat removal capability by containment sprays and fan coolers.

- Estimation of head loss due to LOCA generated debris accumulation on the strainer surfaces.

- RHR suction inlet design including air ingestion and vortex formation and PWR sump design.

- Water drainage within the containment.

- Potential for surface fouling of the secondary sides of the fan coolers, recirculation, and residual heat removal heat exchangers by the cooling water over the life of the plant and the effect of surface fouling on the heat removal capability of the heat exchangers.

SRP 6.2.2 cites NUREG-0897, Rev. 1 [6], for technical considerations pertinent to these matters. One important example of this technical guidance is a step-by-step guide to calculating available NPSH.

SRP 6.2.1.5, Rev 4 Minimum containment pressure analysis for PWR ECCS system performance capability is addressed from the standpoint of determining the dependence of the core flooding rate on containment pressure (i.e., short term phenomena). This SRP section has limited applicability for NPSH analysis in determining the potential for granting a containment overpressure credit, but it does not specifically address long term containment cooling.

10 CFR Part 50, Appendix K Required and acceptable features of ECCS evaluation models are specified in Appendix K. Subsection A deals with sources of heat during a LOCA and subsection D deals with post-blowdown ECCS heat removal phenomena. Pertinent paragraphs include:

- Paragraph I.D.1 states that an analysis of possible failure modes of ECCS equipment and of their effects on ECCS performance must be made. In carrying out the accident evaluation the combination of ECCS subsystems assumed to be operative shall be those available after the most damaging single failure of ECCS equipment has taken place.

- Paragraph I.D.2 states that the containment pressure used for evaluating cooling effectiveness during reflood and spray cooling shall not exceed a pressure calculated conservatively for this purpose. The calculation shall include the effects of operation of all installed pressure-reducing systems and processes.

- Paragraph I.A states that it shall be assumed that the reactor has been operating at a power level at least 1.02 times the licensed power level (to allow for such uncertainties as instrument error), with the maximum peaking factor allowed by the technical specification.

- Paragraph I.A.4 states that the heat generation rates from radioactive decay of fission products shall be assumed to be equal to 1.2 times the values for infinite operating time in the ANS Standard.

2.2 Need for Further Clarification

The review identified several areas where additional clarification is needed. Inconsistencies and errors in the NPSH analyses prepared by utilities have been documented, such as those described in GL 97-04. These inconsistencies include non-conservative assumptions, failure to account for uncertainties, inappropriate use of the hot-fluid correction factor, incorrect strainer head loss, and the inappropriate pump flow rates. Areas where further clarification is needed are now discussed.

Systems Addressed Both the 10 CFR Part 50 and the SRP (CSB 6-1) require the licensees to address all installed pressure suppression systems, not just the pressure suppression systems that are rated as safety class. This is an important distinction in the case of BWRs where the sprays are not rated as safety class, but are installed pressure suppression systems. BWR drywell coolers can also remove heat from the containment atmosphere but are not safety rated. The issue is important to determining available containment overpressure.

Containment Pressure for NPSH Analysis RG 1.1 states that no increase in the containment pressure from that present prior to LOCAs is to be used in NPSH analysis, i.e., the containment operating pressure (lower TS value) while the SRP states simply atmospheric pressure, i.e., 14.7 psia. The motivation of using the initial containment pressure is that this pressure determines the initial noncondensible gas in the containment, i.e, once all water vapor is condensed, the containment pressure will not be less than this initial containment pressure (assuming no leakage and neglected temperature changes). Note that subatmospheric containments operate at less than the standard atmospheric pressure, for example, in the North Anna plant the highest allowed air partial pressure is 12.2 psia at a temperature of 105 °F (FSAR). Thus, North Anna's initial containment pressure would be more than 2.5 psi below one standard atmosphere corresponding to 5.8 ft-water. Other plants operate with a small positive pressure (with respect to atmospheric pressure); for example, the Duane Arnold plant took credit for an initial containment pressure of 0.5 psig (Duane Arnold GL 97-04 submittal) that corresponds to 1.1 ft-water. The regulatory guidance does not specifically address the effects of containment leakage or the altitude of the plant.

The SRP modified the RG 1.1 position by stating that the NPSH analysis should be based on the assumption that the containment pressure equals the vapor pressure of the sump water. The vapor pressure of water depends on the water temperature and can be very different than the initial containment pressure, as illustrated in Figure 1. For example, the difference between one standard atmosphere and the vapor pressure at 160 °F is 9.96 psi corresponding to 23 feet of water at standard density. For plants with marginal NPSH margin, this is not a trivial difference. In fact, it is likely that a substantial number of plants can not show adequate NPSH margin if the vapor pressure of the pumped fluid is used in the analysis. This is illustrated in the detailed review of the Duane Arnold NPSH analysis in Section 5. The issue is discussed in detail in Section 5.

The containment pressure actually being used by the utilities may vary from utility to utility. Certainly some utilities are using the standard atmospheric pressure, Duane Arnold for example. It is likely that a utility would use the maximum of the two pressures, i.e., maximum of the vapor pressure and the standard atmospheric pressure.

Overpressure Credit As part of licensing and reviews, the NRC staff has selectively allowed limited credit for a containment pressure that is above the vapor pressure of the sump fluid to satisfy NPSH requirements. In the case of PWRs, SRP 6.2.1.5 (and CSB 6-1) provides qualitative guidance to estimate minimum containment pressure following a LOCA. The utility may follow CSB 6-1 to estimate minimum containment pressure.

In the case of BWRs, however, no formal guidance is provided to estimate minimum containment pressure (i.e., guidance similar to CSB 6-1). Possibly as a result, the UFSAR for BWRs employed a variety of

different techniques to estimate containment pressure following a LOCA. For example, several BWRs ignore pressure suppression as a result of drywell spray operation because it is not a rated safety system. As a result, the UFSAR containment pressure curves may in actuality not be as conservative. Also, it is not uncommon that two plants, which are otherwise very similar, may have been approved to take credit for substantially different containment overpressures.

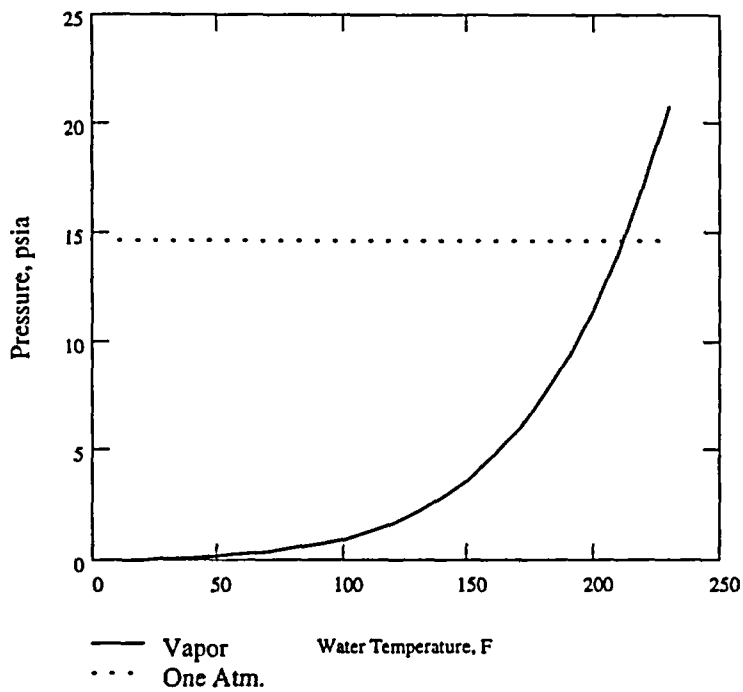

Figure 2-1: Vapor Pressure of Water

It should be noted that the minimum containment pressure does not occur simultaneously with the maximum sump water temperature; rather, the minimum pressure would occur with maximum containment cooling whereas the maximum water temperature occurs with minimum containment cooling. Therefore, granting an overpressure credit based on maximum containment cooling to be used concurrently with the maximum water temperature based on minimum containment cooling is conservative. This issue is addressed calculationally in Section 5.

Decay Heat The determination of the maximum sump or suppression pool water temperature is strongly dependent upon the correlation used for calculating the time-dependent core decay heat power. The required decay heat standard is not specified in the SRP 6.2.2, RG 1.1, or RG 1.82. However, the 1971 ANS standard is specified in 10 CFR Part 50, Appendix K along with two safety factors, i.e., a 2% increase in the licensing power to account for instrument error and a further 20% increase in the assumed rate of heat generation, presumably as a safety factor. Note that there is a more recent ANS decay standard, ANSI/ANS-5.1-1979. There is uncertainty as to the decay heat correlations and safety factors employed by the utilities.

Further, while artificially increasing the decay heat power, as a safety factor, is valid for calculating the maximum pump fluid water temperature, it is not valid for calculating a minimum containment pressure. Rather, an artificial reduction in power would be needed to conservatively predict minimum containment pressure. Note that the SRP 6.2.1.5 guidance for calculating a PWR minimum pressure specifies that 10 CFR Part 50 Appendix K should be followed, i.e., an increase in power.

Staying Current with Plant Modifications and Aging Uncertainty exists as to whether or not NPSH analyses are undated as plants undergo modifications and as components such as heat exchangers and piping age.

Plant modifications to applicable systems could alter their performance and thereby alter their corresponding NPSH margins. The SRP requires the evaluation of the potential for surface fouling of the secondary sides of the RHR heat exchangers by the cooling water over the life of the plant and the effect of surface fouling on the heat removal capability of the heat exchangers. The implication is that over time the heat removal capability of these systems may degrade, thereby increasing the maximum potential sump or suppression water temperature with a corresponding reduction in NPSH margin. Note that the SRP did not consider potential heat exchange fouling on the primary side as well. Further, as pipes age, their surface roughness can increase with a correspond increase in frictional pressure losses.

Appropriate Methods to Predict NPSH The calculation of the available NPSH is reasonably straightforward and is a standard engineering practice; however, calculational errors have been documented, such as the incorrect use of the hot correction factor at Maine Yankee, as described in GL 97-04.

Strainer Head Loss NPSH analysis must account for head losses across the strainer, and considerable inconsistencies and errors associated with these predictions are likely. Historically, predictions for head losses across strainers were based on analytical models (possibly undocumented models) rather than on experimental data. Further, strainer blockage predictions have been based on an assumption that the strainers were 50% blocked. Note that blocking 50% of the holes completely, as might happen if several large pieces of debris were on the strainer, is not the same as partially blocking all the holes with a fibrous debris bed.

PRA versus Licensing Basis NPSH analysis have typically considered design basis LOCAs with the maximum sump pool temperature determined using the 10 CFR Part 50 single failure criterion. There is growing concern that NPSH analyses should be based on more extensive PRA evaluations, i.e., the full spectrum of accident sequences and the impact of the loss of NPSH margin on the CDF.

2.3 Maintaining Multiple Documents versus a Single Guidance Document

This review found existing NPSH guidance generally intractable and in need of clarification in several areas. None of the existing documents function as a comprehensive road map to lead an analyst through a NPSH analysis. The use of multiple documents likely contributed to the documented inconsistencies and errors in NPSH analyses.

An important consideration in whether or not to subsume documents into one document is the maintenance of document functionality. The documents containing NPSH guidance and requirements have one of three basic functions, i.e., federal law (10 CFR Part 50), NRC guidance to the utilities (RG), and guidance to NRC staff in reviewing utility analysis (SRP). Combining documents of different functions likely would cause other problems. For example, combining the RGs and SRP 6.2.2 into a single document would either leave a gaping hole in the SRP or inflate SRP Section 6.2.2 out of proportion with the rest of the document, depending upon whether the resulting document were a RG or a Section in the SRP.

Combining RG 1.1 and RG 1.82 into a single RG could have several advantages, such as:

- An opportunity to include needed additional clarification and to resolve potentially conflicting guidance.
- An opportunity to incorporate new guidance, such as overpressure guidance for BWRs or performing PRA evaluations if needed.
- More comprehensive guidance with a complete roadmap to related documents.
- Reduction in errors associated with incomplete analyses.
- Facilitate both utility NPSH analyses and the NRC review process.

Note that the current versions of RG 1.1 and RG 1.82 each address a different aspect of the NSPH analyses. RG 1.1 addresses containment thermal hydraulics conditions while RG 1.82 considers matters related to strainer blockage. This compartmentalization could be maintained but there is still a need for one of the documents to be comprehensive.

The recommendation of this study is that RG 1.1 be withdrawn and RG 1.82 be revised (i.e., Revision 3) into a comprehensive Regulatory Guide that clarifies existing guidance and functions as a complete roadmap to all related documents. Such documents include applicable paragraphs in the Code of Federal Regulations, applicable sections in the SRP, applicable technical documents such as NUREGs, and other appropriate regulatory documents. Simultaneously, applicable sections of the SRP would require updating at the same time to ensure complete guidance without conflicts. It is further recommended that a sample comprehensive and approved PWR and BWR NPSH analysis be provided to the utilities that can be used as a template for other analyses to facilitate completeness, standardization, and NRC review.

3.0 DETERMINATION OF NPSH

The calculation of the NSPH margin is standard engineering practice and is reasonably straight-forward; however, calculational errors and oversights have been documented in NPSH analyses. Therefore, a relatively comprehensive presentation of the equations and discussions of the controlling physical phenomena are included in this section.

Section 3.1 contains a relatively complete discussion of the thermal hydraulic phenomena affecting the available NPSH. Section 3.2 provides the equations for calculating NPSH including some discussion regarding parameter sensitivities. The basic NPSH available equation was derived from first principles to provide further understanding regarding the terms of the equation. Considerations specific to BWR and PWR plants are discussed in Sections 3.3 and 3.4. Finally, a step-by-step procedure for calculating NPSH margins is presented in Section 3.5. This procedure is based on SEA's understanding of the regulatory guidance.

A methodology for estimating available containment pressure was not specifically presented in Section 3 because there is insufficient guidance available for writing a procedure to describe the process. Rather, aspects of the important phenomena are discussed in Section 3.1 and an example analysis illustrating the determination of available containment pressure is presented in Section 5.

3.1 Bounding Containment Thermal Hydraulic Conditions

The basic objective of NPSH analysis is to determine the minimum available NPSH that can exist during the range of postulated accident scenarios where long-term recirculation cooling is needed. This minimum available NPSH is then compared with the pump-specified required NPSH. An adequate positive margin is required to ensure safe operation.

Since available NPSH depends heavily on the transient thermal hydraulic conditions existing within the containment, the available NPSH is therefore also transient. One of two methods can be applied to determine the minimum available NPSH. One method would be to calculate the time-dependent NPSH and deduce its minimum value. The other method is to determine the worst case thermal hydraulic conditions and then calculate the available NPSH for those conditions. Historically, the second method has been used. The transient thermal hydraulic conditions that significantly affect the available NPSH are the temperature of the pumped fluid, the containment pressure, the height of the water pool above the pump suction inlet, and the pump flow rate (if the flow is postulated to vary during the sequence).

Of these parameters, the most significant parameter is generally the pumped fluid temperature, i.e., the temperature of the suppression pool in BWRs or the sump in PWRs. The pool temperature greatly influences the vapor pressure of the water and more mildly influences friction losses (due to variations in the water density and viscosity). RG 1.1 specifies that the maximum expected temperature must be assumed in NPSH analysis, and it is prudent to use conservative assumptions when predicting this maximum pool temperature.

The calculation of the maximum pool temperature requires a time-dependent calculation. With enough simplifying assumptions, a hand calculation is possible. Since these assumptions ignore various heat removal mechanisms from the containment, the assumptions are therefore conservative. For example, if heat transfer into the concrete walls is ignored, the maximum predicted pool temperature would be conservatively high. More sophisticated calculations, of course, can be performed with computer codes, i.e, codes specifically developed for this type of analysis or system level codes such as MELCOR and CONTAIN. Section 5 contains MELCOR simulations of the maximum pool temperature.

An additional very important consideration in predicting a conservative pool temperature is the assumed reactor power level and the decay heat standard used to calculate decay heat power as a function of time. Regulatory guidance in this regard was discussed in Section 2. Here we will simply note that the power level must be conservatively high to predict a conservatively high maximum pool temperature.

The water height is also transient during the calculations. The height varies due to:

- Water entrained in the containment or in ECCS piping and thus not available for pump suction.
- Addition of injected water from the external sources.
- Water expelled from the reactor cooling system.
- Swelling or contraction as the water heats or cool.
- Clearing and refilling of the downcomers in a BWR.
- Screen blockage in a PWR.
- Ice melting in an ice-condenser plant.

A fully integrated calculation can be performed that determines the water height as a function of time, but when such a calculation is not feasible, an analysis should be performed to determine a conservatively low level by conservatively estimating all factors that can affect the water height.

The actual containment pressure also varies with time; however, regulatory guidance requires the analyst to assume the containment pressure is either atmospheric pressure or the pumped fluid vapor pressure (discussed in Section 2). One purpose of assuming one of these two pressures, as opposed to using the actual containment pressure, is to reduce reliance upon complex computer codes and their associated uncertainties. In addition, if containment integrity were lost, the actual containment pressure would be the local atmospheric pressure, therefore the NPSH margin would not be lost as a result of losing containment integrity.

When a credit for overpressure is required to show adequate available NPSH margin, the associated minimum pressure analysis will necessarily require analysis with relatively complex computer codes. This is necessary because all means of removing heat from the containment will have to be considered in order to ensure a conservative answer. Note that this is quite the opposite of calculating a conservative maximum pool temperature. Regulatory guidance states the all installed pressure-reducing systems and processes must be included in the analysis. These systems and processes include:

- Heat transfer to containment structures
- Containment leakage
- Containment sprays
- Fan coolers
- RHR heat removal heat exchangers
- Power conversion systems.

Internal heat transport processes can also affect the containment pressure response to time-dependent heat sources and sinks. Specifically, the evaporation rate from a pool surface is time-dependent, not instantaneous. The pool surface cools as water evaporates leaving the surface at a slightly lower temperature than the bulk of the pool, especially if the pool is relatively calm as would be the case during long term recirculation cooling. As water evaporates from the surface, heat is transported from the bulk of the pool to the surface. The impact of this pool surface heat transfer is that as the pool heats, the vapor pressure in the containment atmosphere lags behind the saturation pressure of the pool. This effect is illustrated calculationally in Section 5.

Friction pressure losses in piping leading to the pump suction are highly dependent upon the pumping flow rate (proportional to the flow velocity squared). Therefore, friction losses are accident sequence dependent and time-dependent if the flow is varied during the sequence. For example, the pumps might be run at runout flow rates for an initial period of time and then slowed to rated flow for long term.

Available NPSH is strongly dependent upon accident sequence selection because:

- The accident sequence determines the number of pumps operating on a given system, i.e., piping flow rates.

- The containment thermal hydraulic conditions depend upon postulated systems failures and successes.

Therefore, determining the accident sequences applicable to bounding the available NPSH margin requires systems analysis. Historically, the system analysis has assumed that containment conditions could be bounded by LOCA sequences; however, the adequacy of this assumption has been questioned regarding crediting overpressure [7]. More extensive PRA evaluations have been recommended for completeness with respect to ensuring adequate NPSH margin for a full spectrum of accident sequences. Note Section 4 discusses this subject further and provides results for a screening level PRA survey.

3.2 NPSH Model

A water pump requires both an adequate inlet water supply and a total head at the inlet that exceeds the vapor pressure of the water by an amount sufficient to overcome the associated entrance and piping friction losses. The manufacturer of each pump has predetermined the NPSH actually required by the pump (a function of pump speed and pump capacity). The NPSH actually available is determined by the pump application, as illustrated in Figure 3-1. When the available NPSH, exceeds the required NPSH, then there exists a positive NPSH margin but if no NPSH margin exists, cavitation could occur within the pump. The calculation of the NPSH margin is simply:

$$NPSH_m = NPSH_a - NPSH_r$$

(Equation 3-1)

Where $NPSH_m$ = the NPSH margin
$NPSH_a$ = the available NPSH
$NPSH_r$ = the manufacturer required NPSH

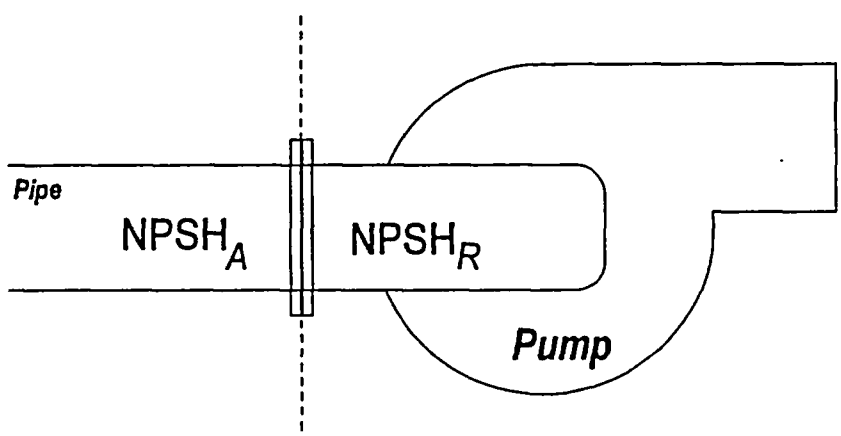

Figure 3-1: Schematic Illustrating NPSH Definitions

Note that NPSH is usually expressed in terms of feet of standing water (ft-water) at the reference density of 62.4 lbm/ft^3, therefore the analyst must be careful with the use of densities.

The definition of available NPSH, as defined by Marks' Mechanical Engineering Handbook [8], is the absolute pressure at the pump inlet, plus the velocity head, minus the vapor pressure of the pumped fluid. This is expressed in Equation 3-2.

$$NPSH_a = \frac{1}{\rho_{std}} \cdot \left(P_e + \rho \cdot \frac{V_e^2}{2g} - P_v \right)$$

(Equation 3-2)

Where P_e = the absolute pressure at the pump inlet
P_v = the vapor pressure of the pumped fluid
V_e = the flow velocity at the pump inlet
ρ = the fluid density at the pump inlet
ρ_{std} = the reference density
g = the acceleration of gravity (32.174 ft/sec^2)

The Bernoulli equation for steady incompressible flow is used to determine the absolute pressure and velocity head at the pump inlet [9, 10]. This Bernoulli equation including a friction loss term and the notation shown in Figure 3-2 follows:

$$P_e + \rho \cdot \frac{V_e^2}{2g} + \rho \cdot Z_e = P_s + \rho \cdot \frac{V_s^2}{g} + \rho \cdot Z_s - \Delta P_f$$

(Equation 3-3)

Where $P_{e,s}$ = the absolute pressures
ΔP_f = the pressure drop the piping to the pump due to friction
$V_{e,s}$ = the flow velocities
$Z_{e,s}$ = the elevations
ρ = the fluid density at the pump inlet
s : indicates the surface of the water
e : indicates the pump inlet

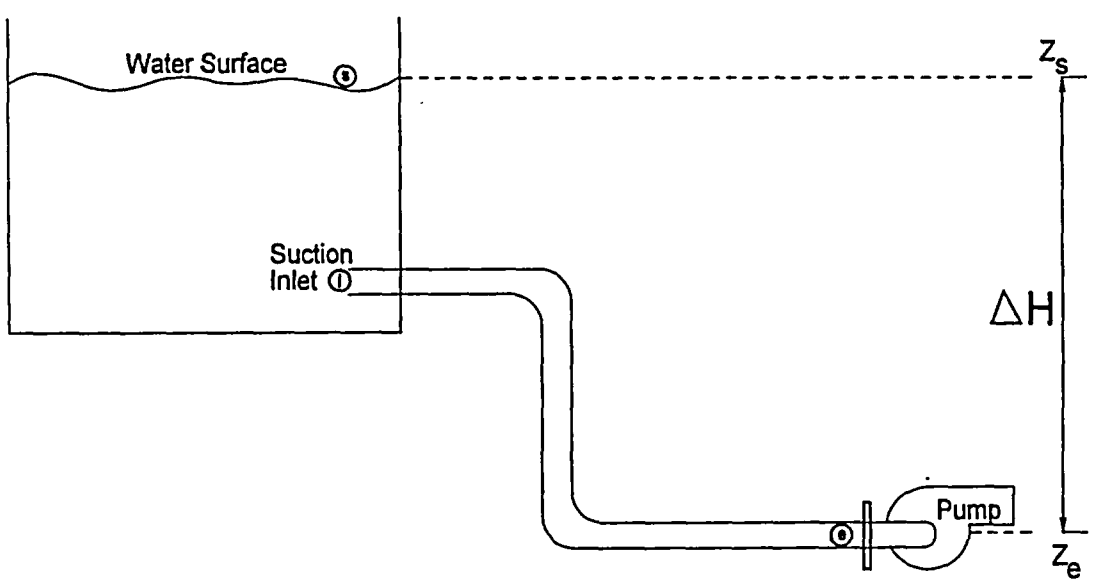

Figure 3-2: Schematic Drawing of System

By first acknowledging that the flow velocity at the pool surface is zero, and defining ΔH as the difference between the pool surface and pump (centerline) elevations, Equations 3-2 and 3-3 reduces the equation normally used to calculate the available NPSH.

$$NPSH_a = \frac{144}{\rho_{std}} \cdot \left(P_s + \frac{\rho \cdot \Delta H}{144} - P_v - \Delta P_f \right)$$

(Equation 3-4)

Note that the velocity head term drops out during the derivation and does not belong in Equation 3-4. This determination is important because some NPSH analyses have incorrectly included a velocity head term in the NSPH available equation; an error likely caused by not including the velocity head term in the definition of available NPSH.

Further, note that the units in the above equation are psia for the absolute pressure at the water surface and the vapor pressure; psi for the frictional pressure drop; feet for the elevation difference; and lbm/ft^3 for the water densities. Further note that the ratio of the actual density to reference density is sometimes referred to as the hot-fluid correction factor and that a common oversight has been to use the same number for both densities.

Other conditions may apply to the calculation of available NPSH, such as the potential for air ingestion. Air ingestion can have a detrimental effect on the operation of the pump; therefore, if the potential for air ingestion is significant, its impact should be evaluated. Guidance for evaluating the impact of air ingestion is found in NUREG-0897, Rev. 1 [6]. Sump vortices can become important if the pumps are not located at significant distances from the sump.

The appropriate pressure to be used for P_s depends upon the purpose of the calculation. If the actual available NPSH is calculated, then the actual containment should be used. But when an available NPSH acceptable to the NRC for licensing is calculated, the water surface pressure must be the pressure specified by the NRC, as spelled out in RG 1.1 and the SRP. Further, if the NRC has approved an overpressure credit, then this credit should be added to the regulatory guidance pressure.

Estimation of the friction loss and form loss associated with the piping between the strainer and the pump is standard engineering practice. The Crane Company has published an excellent reference [10] for calculating friction and form losses in piping. These losses are generally predicted using an equation of the following form.

$$\Delta P_f = \frac{1}{144} \cdot \left(\sum_n K + \frac{fL}{D} \right) \cdot \rho \cdot \frac{V^2}{2g}$$

(Equation 3-5)

Where ΔP_f = the total friction and form loss, psi
V = the flow velocity in the pipe, ft/sec
K = the form loss coefficients
f = the friction factor
L = the pipe length, ft
D = the pipe diameter, ft
ρ = the water density, lbm/ft^3
g = $32.174 ft/sec^2$

Pressure losses through piping and strainers are dependent primarily on the flow velocity through these components and relatively mildly on the water temperature. Note that these pressure losses are

proportional to the square of the flow velocity, i.e., if the flow rate doubles, as would the case if two identical pumps were pulling flow through the pipe as opposed to one, the resulting pressure losses would increase by a factor of four. For example, if the piping friction losses were 3 ft-water and the strainer losses were 2 ft-water when a single pump was running, then the total losses with two identical pumps running would become 20 ft-water (i.e., 4 times 3 plus 2). Thus, NPSH can be greatly reduced when only one pump is operated as opposed to two pumps.

The friction factor will change only slightly with changes in pool temperature as illustrated with the Moody diagram [9]. At the higher Reynolds numbers applicable these piping systems, the friction factors are relatively constant for a given surface roughness. Pressure losses are somewhat dependent on water density but the density will change only a few percent. However, the potential for surface corrosion must be considered in specifying the surface roughness that determines the friction factor.

3.3 Considerations Specific TO BWRS

The water height in a BWR does not vary greatly from the operating level of the wetwell. But still the height will vary due to:

- Water trapped on the drywell floor or in ECCS piping
- Addition of injected water from the external sources
- Water expelled from the reactor cooling system
- Swelling or contraction as the water heats or cools
- Clearing and refilling of the downcomers.

In a BWR plant, the minimum water level also depends somewhat upon the pressure differential between the wetwell and the drywell that in turn depends upon the opening pressure of the vacuum breakers. Note that the wetwell pressure is tends to be higher in the wetwell as the pool heats than in the drywell resulting in water being pushed up into the downcomers. An analysis based on actual containment pressures should consider this effect.

When a fully integrated calculation is not practical, a conservative estimate can be determined by reducing the wetwell minimum operating level by an amount equivalent to the drywell floor volume below the entrances into the vent/downcomers plus the volume of the associated ECCS piping. At the same time, however credit can not be taken for water additions to the suppression pool unless these quantities are known with certainty. Note that there are considerable differences among plant designs, even among the Mark I, for instance. For example, the height from the drywell floor to the entrances into the vent/downcomers varies from plant to plant (from as little as about 6 inches to at least 18 inches). Thus, the adjustment to the minimum operating level is plant specific.

In a BWR, the strainers are located on the pump suction inlets and are therefore below the suppression pool surface. All pump flows must pass through these strainers, therefore, the pressure losses across these strainers must be included in the friction pressure loss term, ΔP_f, of Equation 3-4. Further, the strainer pressure loss must include both the pressure losses associated with a clean strainer (no debris) and any losses associated with debris accumulation on the strainer.

Estimating head losses across a strainer, both clean and partially blocked, is difficult to do analytically. A much better approach is to use experimentally measured data, especially data for the specific strainer in question. The next best approach is scale data measured from a similar strainer. For example, a truncated cone with a total screen area of 18 ft^2 was tested by the BWROG [11], at a flow of 10,000 GPM and a water temperature of 60 °F, and found to have a clean strainer head loss of 2 ft-water. Further, the head loss was shown to vary with the flow rate squared, as theory would predict, i.e., the loss at 5,000 GPM was 0.5 ft-water. Other strainers of different size or even a partial blocked strainer can be roughly estimated using the following scaling equation.

$$\Delta P = \frac{1}{B^2} \cdot \frac{\rho}{\rho_{exp}} \cdot \frac{G^2}{G_{exp}^2} \cdot \frac{A_{exp}^2}{A^2} \cdot \Delta P_{exp}$$

(Equation 3-6)

Where ΔP = the strainer head loss, psi
ΔP_{exp} = the experimentally measured head loss, psi
B = the fraction of strainer holes not blocked
G = the strainer volumetric flow rate, GPM
G_{exp} = the experimental volumetric flow rate, GPM
A = the strainer area, ft^2
A_{exp} = the area of the tested strainer, ft^2
ρ = the water density, lbm/ft^3
ρ_{exp} = the water density test conditions, lbm/ft^3

The Equation 3-6 is based on the friction loss Equation 3-5 and it assumes that the total loss coefficient for the strainer being evaluated is the same as the total loss coefficient tested strainer.

The blockage fraction, B, in Equation 3-6, assumes that a fraction of the holes are totally blocked with the remainder of the holes totally open. This scenario could happen if a few relatively large pieces of debris, such as sheets of plastic, were plastered across portions of the strainer. When considering LOCA generated debris, a more realistic picture of blockage would consider a partial blockage of all of the holes simultaneously by LOCA generated fibrous debris. RG 1.82 and NUREG/CR-6224 [12] contain guidance regarding this type of blockage. Note that if 50% of the holes are completely blocked, the strainer head loss will likely increase by a factor of four over the same unblocked strainer.

3.4 Considerations Specific to PWRS

Determining the water height is somewhat different for a PWR than for a BWR. First of all, the PWR sumps are initially dry and must be filled by water from the external sources, such as the RWST, and from water expelled from the RCS, making it more difficult to conservatively estimate the height. Secondly, PWR containments may have more places where water from the RCS and containment sprays can be entrained and thus not available to the sump (than does a BWR), such as the refueling pool, the outer annulus, the reactor cavity, quench tank, ice condenser compartment, ECCS piping, and stairwells. It is important that a careful, comprehensive, and conservative estimate of the potential for water entrainment be made. Further, the water height is more likely to fluctuate due to changes in ECCS operating parameters (e.g., pump flow rates) and debris accumulation because of the relatively small size of the sump and the irregularities of the surrounding compartment geometry and equipment contained therein. Note that sump and drywell floor geometries are highly plant specific. A careful and comprehensive consideration of the sump and drywell floor geometry is necessary in determining how the pool water volume will vary with altitude. In ice condenser containments, the rate of ice melting is important if this water mass is considered in the NPSH analysis.

It is important to understand that the role of strainer blockage is much different in a PWR than in a BWR. In a PWR, the strainer is located around the sump entrance, rather than on the pump suction inlet. Essentially, the sump screen creates two water levels, i.e., the level inside the screen and the level outside the screen. The difference in these levels depends on the head losses associated with the flow of water through the screen, i.e., the more debris blockage on the screen the greater would be the level difference. Note that the containment pressure above each of these two water levels would necessarily be identical.

It is very important that the correct level be used in the water height tern in Equation 3-4. Although, the total water flow must pass through this screen (assuming that the water level does not top the screen), the screen does not exist physically between the first water surface level connected to the containment atmosphere and the pump suction inlet. The correct height is the elevation difference from the pump

suction centerline to the water level inside the sump strainer and definitely not the level outside the sump screen. If substantial debris were to accumulate on the sump screen, the water level inside the sump could drop dramatically while the level outside the screen remained relatively high.

However, determining the strainer head losses across the screen is still a necessary step in determining the available NPSH because this determination is necessary to determining the water level inside the sump screen. Regulatory guidance for determining the sump screen head losses is found in RG 1.82, Rev. 2. The comments for BWRs (Section 3.3) regarding the use of experimental data where available, are just as applicable to the PWR situation.

As a final note on the subject, if the PWR were also to have a strainer on the pump suction inlet, as well as a sump screen, then this strainer head loss must be to the friction loss term, as it is for BWRs.

3.5 Calculational Methodology for NPSH Analyses

The preceding sections have discussed both the existing regulatory guidance and the thermal hydraulic considerations associated with determining the minimum NPSH margin. As noted in Section 2, the guidance exists in multiple documents and several aspects need additional clarification. Therefore, the potential exists for an NPSH analyst to become confused when interpreting the regulatory guidance or to miss an important aspect of the analysis. This section outlines a calculational methodology based on SEA's interpretation of the regulatory guidance. Further, this methodology is presented as a guide for calculating NPSH margins, i.e., in a step by step approach.

The overall NPSH analysis involves several interrelated steps, as illustrated in the methodology chart shown in Figure 3-3. An acceptable order for stepping through the methodology chart is outlined below.

Plant Data An initial step in calculating the NPSH margins is to gather the required plant design and operation data. These data include:

- Plant IPE PRA analyses
- Containment design data specifying the shape and elevations of the sump or suppression pool
- Elevations of the pumps suctions at the pumps and in the sump or suppression pool
- Pump flow rates
- System descriptions including detailed piping layouts
- Reactor licensed operating power
- Water masses
- Strainer/Screen designs
- Containment operating conditions
- NRC approved overpressure and local atmospheric pressure
- Heat exchanger design data
- Sources of operational and LOCA generated debris
- Accepted debris transport data.

Accident Sequence Analysis The appropriate accident sequences for analysis must be determined. Per SRP 6.2.2 and 10 CFR Part 50, Appendix K, systems analyses must be performed to ensure that no single failure could incapacitate the entire system. Based on the worst-case single-failure sequences and possible subsequent operator actions, the most limiting case, in regards to long-term cooling following the design basis LOCA, should be identified.

A likely limiting case would be a sequence with minimum containment heat removal using a safety rated system, i.e., one RHR heat exchanger, one pump operating on the primary side of the heat exchanger, and one service water pump. If this sequence is not the most limiting case, justification should be provided for using something less limiting.

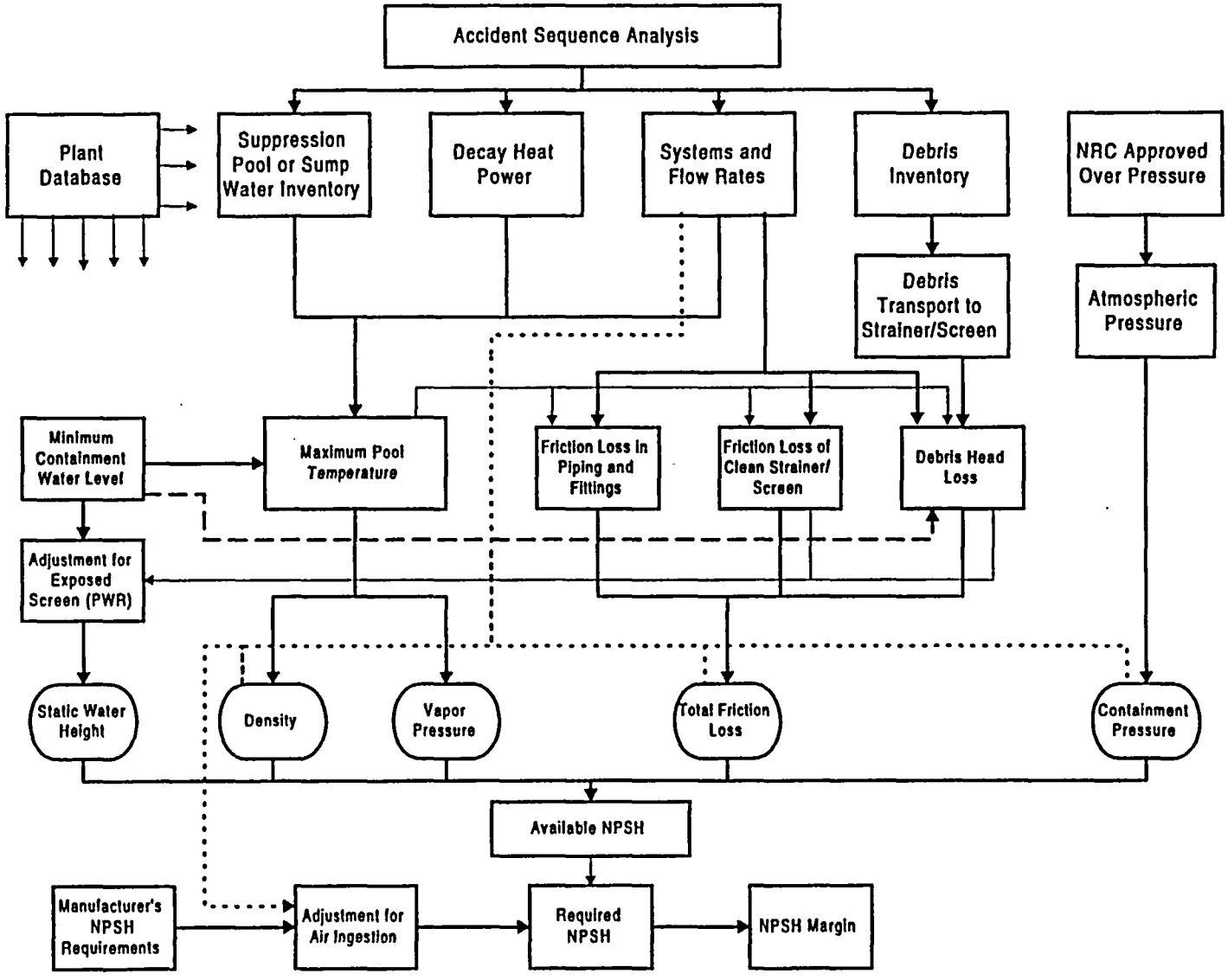

Figure 3-3: NPSH Calculational Methodology

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Identify Systems and Pump Flow Rates Identify the systems, piping, and pump flow rates, applicable to the most limiting case and other sequences analyzed. Specifically, would the pumps be operated at the runout, the rated, the design, or other flow rate and if a rate changes during the sequence, when does the rate change?

Water Inventory Analysis Determine the minimum mass of water available to the sump or suppression pool. Consider all of the following:

1. Conservative minimum estimates of water masses in the containment prior to the LOCA, such as the water in the suppression pool (use the TS minimum level).

2. Add water from external sources, per the accident sequence system description, e.g., water from a RWST or a CST pumped during an ECCS injection phase following the LOCA.

3. Add internally generated water, e.g., water from melted ice in an ice condenser plant provided NRC approval has been given to take credit for ice melt.

4. Add water from the accumulators if activated by the sequence analyzed.

5. Add the net water mass from the reactor cooling system. The net mass is the RCS water mass prior to the LOCA less the RCS mass during long-term cooling. Note that the net mass could be negative because the water is colder during the long-term cooling than during reactor operation. This depends upon the location of the break and the reactor type.

6. Subtract water mass entrained in the associated ECCS piping.

7. Subtract water trapped at a containment location such that the water does not contribute to the sump or suppression pool mass. Examples of these volumes include the drywell floor in a BWR, or the refueling pool (below open drains), the reactor cavity, the outer annulus if not connected to the sump with adequate openings for drainage, the quench tank, stairwells, or other compartments that do not drain well in a PWR. A thorough review of the containment design is needed.

The end result of the water inventory is the minimum water mass in the sump or suppression pool for each sequence analyzed. These estimates must be conservative.

Decay Heat Power The power from the decay of radioactive fission products is a time-dependent process requiring two specific inputs.

1. The reactor thermal operating power level determines the inventory of fission products in the core. The appropriate power level is the licensed power level increased by 2% to account for instrument error and another 20% as a safety factor, i.e., $P_{analysis} = 1.02 \times 1.2 \times P_{licensed}$.

2. A decay heat correlation is used to predict the normalized time-dependent decay power. Per 10 CFR Part 50, Appendix K, the ANS Standard should be used. The latest version of this standard is the 1979 version referred to as ANSI/ANS-5.1-1979.

Maximum Pool Temperature A time-dependent calculation based on conservative assumptions is required to determine the maximum pool temperature for each accident sequence analyzed. The calculational model must include:

- The mass of water heated
- The time-dependent decay heat power
- The heat exchanger removing heat from the pool
- The pump flow rates through the heat exchanger

The decay heat power places heat into the pool, the mass of water stores heat, and the heat exchanger removes heat. The pool temperature will continue to increase until the decay heat power drops below the heat removal capability of the heat exchangers. Both the complexity and the uncertainty of the calculation are reduced by assuming that no heat is transferred between the pools and atmospheres and the surrounding structures.

It is important that the heat exchanger model conservatively include the potential for loss of performance due to surface fouling on both sides the tubes.

Water Properties The density and the vapor pressure at the maximum pool temperature are looked up in steam/water property tables.

Minimum Containment Water Level The lowest level of water in the sump or suppression pool is determined from the minimum water mass, the maximum pool temperature, and sump or suppression pool geometry. In a PWR plant, this water level will be the average level across the containment, i.e., the water level drop across the debris screen is not considered here. Rather the level is adjusted in a later step once the debris head loss has been determined.

Piping Friction Loss The head loss in the piping between the suction inlet and the pump inlet is determined from the flow rate(s), the maximum pool temperature, and the configuration, components, and surface conditions of the piping. Calculating head losses is standard engineering practice and several good references are available, such as Reference 10. The important aspects of this calculation are:

- That proper and conservative form loss coefficients be used for all piping components, e.g., valves, elbows, junctions, etc.
- That the surface roughness used to calculate the friction factor must reflect the actual surface conditions of the piping, i.e., aged or corroded as opposed to newly manufactured smooth clean steel.
- That the correct flow velocity is used in each piping component.

Clean Strainer Head Loss The head loss across the strainer, without any blockage by debris, depends upon the design of the strainer, the flow rate, and the water temperature. Where possible this head loss should be based on an appropriate measurement, preferably the actual strainer.

Debris Inventory All sources of debris, both operational and LOCA-generated should be identified per RG 1.82, Rev. 2.

Debris Transport Debris transport to the strainer or screen must be estimated by quantity, type, and other characteristics. Regulatory guidance for debris transport is found in RG 1.82, Rev. 2.

Debris Head Loss Head losses associated with debris deposited on the strainer or screen must be conservatively estimated. Again, the guidance is found in RG 1.82, Rev. 2. This head loss also depends upon the height of water on the screen.

Adjust Minimum Water Level for Debris Head Loss (PWRs only) When the containment sump water level is below the top of the screen in a PWR plant, the drop in water level across the screen associated with the debris plus the clean strainer head losses must be estimated. Unless the drop is substantial, the effect on the overall sump water level should be minimal, therefore the water level inside the sump is simply the overall sump water level previously calculated decreased by a conservative estimate for the drop across the screen. If the water level outside the screen increases significantly with the drop across the screen, then an iterative solution involving both the inside and outside levels and the debris head loss might be needed. If the sump screens are completely submerged, then this water level adjustment does not apply.

Static Water Column Height The static water column height is the difference in elevations between the pump suction centerline and the minimum water level. Note that this is the pump suction centerline and not the pipe inlet at the sump or suppression pool. Note that the pump suction centerline can exist physically either above or below the pipe inlet. In a PWR plant where the sump screen is not completely submerged, the minimum water level is the level inside the screen, not outside.

Total Friction Loss The total friction loss for a BWR plant or a PWR plant with a totally submerged screen is the total of the piping friction loss, the clean strainer/screen head loss, and the debris head loss. In a PWR plant where the screen is not totally submerged, the total friction loss is just the piping friction loss (because the effect of the screen blockage was taken into account by the adjustment in the water level).

Containment Pressure The containment pressure, per existing regulatory guidance, should be the atmospheric pressure plus any NRC approved overpressure credit. In keeping with the spirit of the regulatory guidance, the atmospheric pressure should be the local atmospheric pressure (taking into account plant altitude), i.e., should the containment integrity be lost, it is the actual pressure outside the containment that is important.

Available NPSH The available NPSH can now be calculated from the static water column height, the pool density, saturated vapor pressure, the total friction head loss, and the containment pressure using Equation 3-4.

Required NPSH The required NPSH is the NPSH specified by the pump manufacture as needed to prevent cavitation increased by an amount to account for air ingestion, if applicable. Guidance for determining the adjustment for air ingestion is found in reference 6.

NPSH Margin The NPSH margin is simply the available NPSH less the required NPSH. Note that each pump and each accident sequence analyzed can have different NPSH margins.

Note again that the above methodology included the use of a NRC approved overpressure credit but it did not address the determination of the minimum available containment pressure needed to justify an overpressure credit. Further note that the minimum available containment pressure is not a constant value, rather it varies with the sump or suppression pool temperature. Insufficient guidance is available to write a procedure for determining the minimum available containment pressure, but the reader can refer to Section 5 for an illustrative example showing how the determination of available containment pressure might be done.

Time-dependent analysis is needed to complete two aspects of NPSH analysis, i.e., the calculation of the maximum pool temperature and the calculation of the minimum available containment pressure. The time-dependent analysis for determining the maximum pool temperature can be greatly simplified by conservative assumptions, e.g., ignoring the effects of heat transfer to structures or neglecting non-safety rated systems. However, the time-dependent analysis to determine the minimum available containment pressure can not be simplified by neglecting either pressure reducing systems or processes, rather the required calculations must be comprehensive and detailed. Further, these calculations must consider a complete spectrum of applicable accident scenarios.

4.0 SELECTION OF ACCIDENT SCENARIOS

At the present time, the licensing basis for ECCS is derived from the design basis accident (DBA) analysis where a double-ended guillotine break (DEGB) large LOCA is postulated. As a result, most plants analyze the DBA (i.e., a large LOCA) to establish the most limiting operating conditions (e.g., available pump NPSH) for ECCS operation. However, it is not clear that conditions during a DBA will always bound conditions that might occur in other accidents that are equally likely or even more likely to occur.

To further explore this issue, probabilistic evaluations were made to investigate plant accident scenarios where recirculation cooling from the suppression pool or containment sump is required to maintain adequate core cooling. Initially, recirculation-cooling unavailability was evaluated with regard to its generic impact on core damage frequency (CDF) for various BWR and PWR accident classes. Next, more focused evaluations were performed on a representative BWR and PWR to select beyond-DBA conditions for subsequent deterministic analyses. The focus of these deterministic analyses was to evaluate the NPSH available to pumps needed to support recirculation cooling.

Subsection 4.1 below describes the generic impact of recirculation cooling unavailability on core damage frequency (CDF). Subsection 4.2 describes mitigable, beyond-DBA conditions for two representative plants, including comparisons to DBA scenarios. Finally, the overall findings related to the probabilistic evaluations are summarized in Subsection 4.3.

4.1 Generic Impact of Recirculation Cooling Unavailability on Core Damage Frequency

Recirculation cooling unavailability was initially evaluated with regard to its generic impact on CDF for various BWR and PWR accident classes. This portion of the analysis was begun by reviewing Individual Plant Examinations (IPEs) and other PRA studies to identify accident classes where successful core cooling may require recirculation cooling from the suppression pool or containment sump. Generic failure data were subsequently used to quantify accident class scenarios to estimate generic impacts on CDF, assuming unavailability of recirculation cooling. Results from this generic accident class survey were used to demonstrate the impact that recirculation pump unavailability can have on the CDF for both individual accident classes and the overall plant CDF.

The accident class CDF survey was based on typical IPE and PRA-related studies. The major steps used to accomplish this survey are outlined below:

1. Identify mitigating system success criteria for various initiating events.

2. Identify major assumptions associated with accident mitigation strategies, for example coping time for station blackout accidents, non-recovery probability of loss of offsite power, extent of credit taken for alternate cooling methods.

3. Using mitigating system success criteria and major assumptions gathered in Steps (1) and (2), identify accident scenarios and accident classes where successful core cooling either (a) requires recirculation cooling, or (b) where recirculation cooling can be avoided only if other mitigating systems are operable.

4. If provided, use IPE/PRA risk increase importance measure results to estimate increases in CDF given unavailability of recirculation cooling (note: many IPE/PRA studies do <u>not</u> have this type of importance measure data); where possible, tie the risk increase results back to specific accident classes.

5. If appropriate risk increase importance measures are not provided as specified in Step (4), gather IPE/PRA initiating event frequency data for sequences where (a) successful core cooling requires recirculation cooling, and where (b) recirculation cooling can be avoided only if other mitigating systems are operable; proceed to Step (6).

6. Use IPE/PRA system and/or component failure data to estimate unavailability of front-line mitigating systems that represent alternatives to recirculation cooling (for example, injection of external service firewater can be used at some BWRs if recirculation cooling fails); proceed to Step (7).

7. For cases where there are alternatives to recirculation cooling, multiply the appropriate initiating event frequencies by the unavailabilities of the alternate mitigating systems to estimate accident class frequencies; proceed to Step (8).

8. For cases where there are no alternatives to recirculation cooling, the appropriate initiating event frequencies represent the sequence frequencies; proceed to Step (9).

9. Sort sequences developed in Steps (7) and (8) into accident classes.

10. Add the frequencies of each sequence within a given accident class; these results reflect the impact on accident class CDF values caused by loss of recirculation cooling.

Results from the generic accident class CDF survey for BWRs and PWRs are summarized in Tables 4-1 and 4-2, respectively. As is shown, the following accident classes were evaluated for both BWRs and PWRs: LOCA, transient, station blackout, anticipated transient without scram (ATWS), and interfacing systems LOCA (ISLOCA). For PWRs, an additional accident class was evaluated, steam generator tube rupture (SGTR). For each accident class, the tables include information regarding timing requirements for recirculation cooling, typical accident class CDF values, and the expected impact on CDF if recirculation cooling fails. Also provided are miscellaneous notes, the bases for CDF impact estimates, and document references. In addition, the tables provide the aggregate impact on CDF from all accident classes. The results presented in Tables 4-1 and 4-2 are limited to internal events (including internal flooding). Every effort has been made to generate results that reflect generic (typical) plants.

For both BWRs and PWRs, the results indicate that the unavailability of recirculation core cooling will increase the baseline aggregate CDF values by two orders of magnitude, from the E-05/yr range to the E-03/yr range. For BWRs, the accident classes having their CDF values most affected by recirculation cooling unavailability are the LOCA and transient accident classes. While in some cases BWR LOCAs can be mitigated with injection from external water sources, timing considerations make it difficult to connect external water sources quickly enough to mitigate the larger break sizes. Thus, recirculation cooling has a very important role in mitigating LOCAs. While external water sources can also be used as a backup method of mitigating many types of BWR transient accidents, recirculation cooling would be the preferred method given depletion of the HPCI/RCIC CST supplies. Because the CDF calculations for BWR LOCAs and transients rely so heavily on credit for recirculation cooling, removal of credit for recirculation cooling has a major impact on these accident class CDF values. Table 4-1 indicates that unavailability of recirculation core cooling increases the baseline CDF values for the BWR LOCA and transient accident classes by two orders of magnitude. Specifically, the LOCA CDF increases from 2E-06/yr to 3E-04/yr, and the transient CDF increases from 1E-05/yr to 4E-03/yr.

The CDFs for the remaining three BWR accident classes, station blackout, ATWS, and ISLOCA, are affected to a lesser extent if recirculation cooling is unavailable. In station blackout, there is a very good chance that electrical power will be recovered before CST inventory depletion occurs, thus avoiding recirculation cooling. Plant procedures are typically written so as to preserve CST inventory during station blackout by instructing operators to initially align HPCI to the suppression pool as a water source. This action extends the plant coping time, because use of the CST inventory is delayed until suppression pool conditions (generally high temperature) prevent HPCI pump suction from the pool. For ATWS conditions, feedwater can be used as an injection source. ISLOCA conditions generally involve discharge of coolant outside the primary containment structure, with the result that recirculation is not a viable method of long-term cooling. ISLOCA conditions can be mitigated with the injection of water from various external sources, such as RHR service water and firewater.

Table 4-1: Generic Impact on BWR Accident Class CDF if Recirculation Cooling is Unavailable

Accident Class	Timing Requirements for Recirculation Cooling (Measured from on-set of accident)	Typical Accident Class CDF (IPE Internal Events Results) - per yr.	Expected Impact on CDF if Recirc. Cooling Fails (New CDF) - per yr.	Notes	Basis for CDF Impact Estimates	References
LOCA (all) Large Medium, Small	 ≤ 25 minutes ≤ 1 hour (depends on break size)	2E-06 (all) 2E-07 2E-06	3E-04 (all) 2E-05 3E-04	Typical large LOCA IE frequency is 1E-04/yr Typical combined frequency of other LOCAs (medium/small) is 3E-03/yr (medium = 3E-04/yr, small = 3E-03/yr)	Large LOCA - credit for alternate core injection from external water source (for example, RHR SW or fire water); estimate 0.25 probability that operators fail to align external source in time Medium/small LOCA - credit for typical alternate injection systems (for example, RHR SW or fire water) and the fact that HPCI/RCIC initially draw water from clean source (CST); estimate 0.1 probability that operators fail to align external sources in time, 2E-03 unavailability of external source - total failure probability is approximately 0.1	p. 11-25 of NUREG-1560, Vol. 2 p. 8-8 of NUREG/CR-6224 p. 4-183 of Duane Arnold IPE p. 4.3-15 of NUREG/CR-4550, Vol. 6, Rev. 1, Part 1 Table 3.1-3 of Pilgrim IPE p. 3-432 of FitzPatrick IPE
Transient	1 hour	1E-05	4E-03	Also includes contributions from internal flood Typical transient initiating event frequency is 2/yr with PCS unavail, or 4/yr with PCS avail; LOSP is typically 0.05 - 0.1/yr (PCS unavail) Special initiating events, for example loss of SW or DC bus typically have frequencies between 1E-03/yr to 1E-04/yr	Credit for typical alternate injection systems (for example, RHR SW or fire water) and the fact that HPCI/RCIC initially draw water from clean source (CST); estimate that CST could provide enough inventory for 2-3 hours Transient with PCS avail is not as important as other initiating subcategories; estimate 2E-03 probability that operators fail to align external sources in time after loss of PCS (represents unavailability of RHR SW); CDF impact - (2/yr) x 2E-03 = 4E-03/yr	p. 11-24, 11-25 of NUREG-1560, Vol. 2 p. 4-180 of Duane Arnold IPE p. 4.3-15 of NUREG/CR-4550, Vol. 6, Rev. 1, Part 1 pp. 3-431, 3-432 of FitzPatrick IPE

Accident Class	Timing Requirements for Recirculation Cooling (Measured from on-set of accident)	Typical Accident Class CDF (IPE Internal Events Results) - per yr.	Expected Impact on CDF if Recirc. Cooling Fails (New CDF) - per yr.	Notes	Basis for CDF Impact Estimates	References
Station Blackout	1 hour	1E-05	1.2E-05	Assumes lack of significant recirculation pump seal leakage	Credit for fact that RCIC initially draws water from clean source (CST); estimate that CST could provide enough inventory for 2-3 hours (per procedures, operators are to initially use suppression pool for HPCI water source); plant batteries typically last at least two hours without recharge (to sustain RCIC/HPCI operation) Probability of non-recovery of electrical power within 2 hours is about 0.2; with recovery of electrical power, could restore feedwater RCIC unavailability is 4E-02 HPCI unavailability is 7E-02 (with adequate pump NPSH) Unavailability of both RCIC and HPCI is 3E-03 (with adequate pump NPSH) Probability that cooling cannot be maintained for first 2 hours of a SBO event is: (a) for RCIC and HPCI unavailability - 0.2 + 3E-03 = 2.03E-01 for (b) for RCIC unavailability, assuming HPCI has been lost to inadequate pump NPSH - 0.2 + 4E-02 = 2.4E-01 for RCIC unavailability Ratio of 2.4/2.03 = 1.2 = relative increase in CDF if HPCI is lost to inadequate pump NPSH	p. 11-24 to 11-29 of NUREG-1560, Vol. 2 p. 3-51 of Duane Arnold IPE pp. 3-431, 3-432 of FitzPatrick IPE

Accident Class	Timing Requirements for Recirculation Cooling (Measured from on-set of accident)	Typical Accident Class CDF (IPE Internal Events Results) - per yr.	Expected Impact on CDF if Recirc. Cooling Fails (New CDF) - per yr.	Notes	Basis for CDF Impact Estimates	References
ATWS	15 minutes	1E-06	1.3E-06	Sum of initiating event frequencies that represent RPS challenge could be in range of 6/yr (dominated by transients)	Can use feedwater as injection source Feedwater expected to have a smaller unavailability, 6E-02, than the probability of failure of required ATWS-related operator actions (such as level control to prevent boron flush, failure probability as high as 0.2) - thus impact of inadequate pump NPSH on ECCS pumps probably does not significantly increase the ATWS CDF Ratio of (0.2 + 6E-02)/0.2 = 1.3 = relative increase in CDF if other injection systems besides feedwater not available	p. 11-25, 11-29 to 11-31 of NUREG-1560, Vol. 2 p. 3-377, 3-379 of Duane Arnold IPE pp. 3-431of FitzPatrick IPE pp. E-72, E-73 of FitzPatrick IPE
ISLOCA	≤ 1 hour (depends on break size)	2E-08	1E-08	ISLOCA initiating event frequencies typically in range of 1E-06/yr to 5E-06/yr For very small breaks, time need for injection would be approximately same as for transient	Injection sources typically include ECCS and external water sources, such as RHR SW IPEs typically take substantial amount of credit for eventual isolation of ISLOCA condition Some ISLOCAs can directly disable ECCS systems - no credit is given for ECCS injection in these cases Using typical unavailability of RHR SW of 2E-03, conclude that accident sequence frequency of ISLOCA involving loss of ECCS injection capability is 5E-06/yr x 2E-03 = 1E-08/yr	p. 11-25 of NUREG-1560, Vol. 2 pp. 3-432 of FitzPatrick IPE p. 3-39 of Clinton IPE Table 3.1-3 of Pilgrim IPE
Total		2E-05	4E-03			

Table 4-2: Generic Impact on PWR Accident Class CDF if Recirculation Cooling is Unavailable

Accident Class	Timing Requirements for Recirculation Cooling (Measured from on-set of accident)	Typical Accident Class CDF (IPE Internal Events Results) - per yr.	Expected Impact on CDF if Recirc. Cooling Fails (New CDF) - per yr.	Notes	Basis for CDF Impact Estimates	References
LOCA (all) Large Medium, Small	 30-60 minutes 1 to several hours (depends on break size)	1E-05 (all) 3E-06 1E-05	3E-03 (all) 5E-04 2E-03	Typical large LOCA initiating event frequency is 5E-04/yr Typical combined frequency of other LOCAs (medium/small) is 3E-03/yr (medium = 1E-03/yr, small, very small = 1E-02/yr)	Large LOCA - ECCS recirculation is required; loss of ECCS pumps due to suction strainer clogging will result in core damage Medium/small LOCA - for some very small LOCAs, it may be possible to remain on ECCS injection for many hours, and eventually transition to RHR shutdown cooling (closed loop); also, a few plants have taken credit for refill of the RWST Risk increase for failure to initiate low head recirculation for small LOCA - 1.2E-03/yr Risk increase for failure to initiate low head recirculation for medium LOCA - 9.1E-04/yr Thus CDF with loss of ECCS pumps in recirculation mode for small and medium LOCAs would be approx. 1.2E-03/yr + 9.1E-04/yr = 2.1E-03/yr	p. 11-126 to 11-129 of NUREG-1560, Vol. 2 p. 3-419, J-20 of Indian Point 3 IPE
Transient	Several hours (if feed and bleed is used) Not required if secondary cooling is available	2E-05	2E-04	Also includes contributions from internal flood Typical transient initiating event frequency is 0.5 - 1/yr with main feedwater unavail, or 1 - 2/yr with feedwater avail; LOSP is typically 0.05 - 0.1/yr (feedwater unavail) Special initiating events, for example loss of SW or DC bus typically have frequencies between 1E-03/yr to 1E-04/yr	Credit for main and auxiliary feedwater for secondary cooling; if all secondary cooling fails, credit feed and bleed cooling with ECCS pumps Per Indian Point 3 IPE, risk increase associated with failure of operators to initiate feed and bleed is 2.2E-04/yr (corresponds to no credit for feed and bleed)	p. 11-122 to 11-125, of NUREG-1560, Vol. 2 pp. 3-419, 3-464, J-23, J-29 of Indian Point 3 IPE

Accident Class	Timing Requirements for Recirculation Cooling (Measured from on-set of accident)	Typical Accident Class CDF (IPE Internal Events Results) - per yr.	Expected Impact on CDF if Recirc. Cooling Fails (New CDF) - per yr.	Notes	Basis for CDF Impact Estimates	References
Station Blackout	Several hours (if feed and bleed and/or primary makeup are used after power restoration) ECCS not required if secondary cooling is available and primary makeup not required	1E-05	5E-05	Have potential for RCP pump seal leakage during SBO Typically, majority of SBO CDF contribution is associated with sequences involving failure to mitigate RCP seal leakage	Typical LOSP frequency is 0.05 - 0.1/yr; assuming loss of 2 redundant diesel generators, each with a random start failure probability of 3E-02 and common cause beta factor of 3E-02, estimate frequency of SBO condition to be approx. 1E-04/yr Assuming that 50% of time an RCP seal LOCA occurs that must be mitigated by ECCS after restoration of power (including recirculation mode) - this has an estimated CDF impact of 5E-05/yr; may be conservative, since recovery of electrical power could restore RCP seal cooling so that RCP seal LOCA never takes place	pp. 11-116 to 11-122 of NUREG-1560, Vol. 2 pp. 3-419, 3-464, J-23 of Indian Point 3 IPE
ATWS	ECCS not required (need secondary cooling instead)	1E-06	1E-06		ECCS not required for mitigation	p. 11-111 of NUREG-1560, Vol. 2
ISLOCA	≤ 1 hour (depends on break size)	2E-08	2E-07	ISLOCA initiating event frequency is typically in range of 2E-06/yr	ECCS used for injection source; some plants take credit for refill of RWST IPEs typically take substantial amount of credit for eventual isolation of ISLOCA condition Some ISLOCAs can directly disable ECCS systems - no credit is given for ECCS injection in these cases Assume that only 10% of ISLOCAs will eventually result in ECCS recirculation (due to relief valve that opens inside containment during ISLOCA) 0.1 x 2E-06/yr = 2E-07/yr	pp. 11-133, 11-134 of NUREG-1560, Vol. 2 pp. 3-419 of Indian Point 3 IPE

Accident Class	Timing Requirements for Recirculation Cooling (Measured from on-set of accident)	Typical Accident Class CDF (IPE Internal Events Results) - per yr.	Expected Impact on CDF if Recirc. Cooling Fails (New CDF) - per yr.	Notes	Basis for CDF Impact Estimates	References
SGTR	Several hours (if feed and bleed is used)	2E-06	1E-05	SGTR initiating event frequency is typically 1E-02/yr	Credit for main and AFW for secondary cooling; if all secondary cooling fails, credit feed and bleed cooling with ECCS pumps Do not need primary makeup if affected steam generator isolated and RCS depressurized; even if need primary makeup, credit is taken for refill of RWST Expect unavailability of main feedwater during SGTR to be no greater than 0.1 Expect unavailability of AFW during SGTR to be no greater than 0.01 Unavailability of both main feedwater and AFW is 1E-03 CDF impact without ECCS = 1E-03 x 1E-02/yr = 1E-05/yr	p. 11-132, 11-133 of NUREG-1560, Vol. 2 pp. 3-419 of Indian Point 3 IPE
Total		5E-05	3E-03			

For PWRs, the accident class whose CDF is most affected by the unavailability of recirculation cooling is the LOCA accident class. Unlike BWRs, PWRs do not have any direct means of injection external water (i.e., non-safety sources) to mitigate LOCAs. In several IPEs, credit was taken for refill of the RWST to maintain ECCS pumps in the injection phase, thus avoiding a switch to recirculation. This action would only be viable for very small LOCAs, where sufficient time might be available to replenish the RWST. Given unavailability of recirculation cooling, the PWR LOCA accident class CDF increases by a factor of 600 to 6E-03/yr. The CDF for the PWR transient accident class is also significantly affected by recirculation cooling unavailability. If a transient occurs with loss of all secondary cooling, most PWRs can perform "feed and bleed" cooling using the HPI pumps. Once the RWST is depleted, continuation of feed and bleed cooling requires that the HPI pumps be switched from the injection mode to the recirculation mode. Given unavailability of recirculation cooling, the PWR transient accident class CDF increases by an order of magnitude to 2E-04/yr. The unavailability of recirculation cooling has a smaller effect on the absolute value of CDFs for the remaining four PWR accident classes (station blackout, ATWS, ISLOCA, and SGTR).

4.2 Identification of Beyond-DBA Conditions for Representative Plants

As previously noted, a separate probabilistic screening analysis was made to investigate beyond-DBA conditions for a representative BWR and PWR, using results from applicable IPE studies. The focus of this additional analysis was to identify the most likely beyond-DBA conditions where:

- Successful core cooling is credited by the IPE if mitigating systems properly operate.
- Recirculation cooling is among the required mitigating systems.
- Containment, suppression pool, and/or sump conditions have the potential to be most severe with respect to sustaining recirculation pump operation.

The major steps in this activity are outlined below:

1. Review the IPE event tree models and success criteria to identify beyond-DBA mitigable conditions that require recirculation cooling.
2. For each condition identified in Step (1), list the initiating event, along with all other failures or non-recovery events that must occur to cause the beyond-DBA condition.
3. For each accident condition, use the IPE documentation to quantify the items identified in Step (2), specifically the initiating event frequency and pertinent system failures and miscellaneous non-recovery events.
4. For each accident condition, multiply the initiating event frequency with the quantification of the pertinent system failures and miscellaneous non-recovery events derived above; the product of these data will represent an estimate of the accident condition's frequency.
5. Select the accident conditions that have the highest frequencies.

Subsections 4.2.1 and 4.2.2 below describe the highest-frequency, beyond-DBA, mitigable conditions identified for Duane Arnold and Oconee.

4.2.1 Duane Arnold Beyond-DBA Conditions

Two accident conditions were identified for Duane Arnold having frequencies of occurrence comparable to the traditional large LOCA DBA, but more limiting with regard to sustaining recirculation pump operation. These two accident conditions are summarized below:

Accident Condition No. 1: Extended Station Blackout

A loss of offsite power (LOSP) initiating event occurs, which is followed by the failure of emergency onsite AC sources. Per the IPE, the reactor can be cooled by high-pressure injection from the RCIC and/or HPCI systems, both of which require DC power for their operation. The DC batteries in turn can supply the HPCI and RCIC loads for 12 and 8 hours, respectively, with credit taken for battery load shedding. If all high-pressure injection is lost at 12 hours (HPCI), vessel inventory boil-off would provide an additional 3 hours of core cooling.

In principle, it might be possible to restore coolant inventory with the diesel driven fire pump (DFP) using emergency depressurization of the reactor pressure vessel. However, successful injection with the DFP is questionable when the containment is at high pressure, and the IPE gave very little credit for this alternative cooling method.

The RCIC and HPCI pumps can take water from either the CST or the suppression pool. There are two CSTs with a total capacity of 400,000 gal, of which only 75,000 gal are specifically reserved for HPCI and RCIC (it appears that 75,000 gal is the combined CST inventory for HPCI and RCIC).

Per the IPE, the LOSP initiating event frequency is 8E-02/yr, the probability of non-recovery of LOSP at 15 hours is 1E-02, and the probability of non-recovery of emergency onsite AC power sources is 0.2. Therefore, the frequency of a 15-hour station blackout condition occurring is the product of these numbers, which is 1.6E-04/yr.

Accident Condition No. 2: Loss of all Power Conversion System (PCS) Cooling, RHR Torus Cooling, and Core Spray

A loss of river water occurs as an initiating event, followed by a non-recoverable loss of feedwater/condensate. The loss of river water causes the loss of circulating water makeup (with subsequent loss of main condenser), loss of emergency service water (ESW), and loss of RHR service water (RHRSW). In order for decay heat to be removed, either the containment vent must properly operate, or a mechanical pump must be used to maintain condenser vacuum while well water is maximized as a makeup to the circulating water system to support feedwater/condensate. If the feedwater/condensate system (PCS cooling) is lost, the remaining injection sources would be HPCI, RCIC, and LPCI. Core spray would not available because ESW is required to cool its pumps. Furthermore, the torus-cooling mode of RHR would not available due to the loss of RHRSW.

Per the IPE, the loss of river water initiating event occurs with a frequency of 7.5E-04/yr, while a subsequent loss of feedwater/condensate is 4.5E-01. Therefore, it appears that loss of PCS cooling, RHR torus cooling, and core spray injection will occur with a frequency of 3.4E-04/yr.

To place the frequencies of the above accident conditions in perspective, the Duane Arnold IPE predicts that the traditional DBA (large LOCA) will occur with a frequency of 3E-04/yr. The IPE further predicts that the traditional DBA combined with loss of a single train of RHR HX cooling (single failure) will occur with a frequency of approximately 3E-06/yr.

4.2.2 Oconee Beyond-DBA Conditions

Unlike Duane Arnold, a review of the Oconee IPE failed to identify any individual, beyond-DBA, mitigable conditions that have frequencies comparable to or greater than the traditional DBA (large LOCA) frequency. This situation may be unique to Oconee, or it may be reflective of PWRs in general. While more study would have to be done, this result may be related to the success criteria assumed in the Oconee IPE as well as other PWR IPE/PRA studies. Specifically, in cases where PWR core cooling via sump recirculation is modeled and credited, the accompanying success criteria require some form of external

cooling for the recirculated water and/or the containment atmosphere. Otherwise, IPE/PRA studies assume that the condition cannot be mitigated. There do not appear to be any exceptions to this modeling practice. In contrast, BWR IPE/PRA studies have credited recirculation cooling for extended periods without external cooling of either the recirculated water or containment atmosphere. Two examples of such BWR sequences were previously described.

To accomplish adequate core cooling during the sump recirculation mode, PWR PRA/IPE studies typically assume that one RHR core cooling train (an operating RHR heat exchanger associated with an injecting RHR pump) is required. However, some PWR PRA/IPE studies have further assumed that if RHR heat exchangers are unavailable, adequate heat removal still be accomplished with one or more containment fan cooler units and an injecting RHR pump. For example, the Oconee IPE has assumed the following success criteria for the recirculation phase of a large LOCA:

1. 1 of 2 low pressure injection (LPI/RHR) pump trains taking suction from the sump and injecting into the vessel, and cooling of the recirculation flow with the heat exchanger in the operating LPI train, or

2. 1 of 2 low pressure injection (LPI/RHR) pump trains taking suction from the sump and injecting into the vessel, and reactor building cooling with 1 of 3 reactor building cooling units (RBCUs) (often referred to as containment fan coolers).

The large LOCA probabilistic data in Table 4-3 were derived from a review of the Oconee IPE materials.

Table 4-3. Frequency of a Large LOCA Given Various Core/Containment Cooling Conditions (per reactor yr)

Available LPI Trains With RHR HX Cooling	Available RBCUs			
	0	1	2	3
0 (no RHR HX cooling but core injection avail)	2E-08 (dominated by loss of all LPSW to LPI HXs and RBCUs)	2E-10	1E-09	6E-07
1 (1 RHR HX avail)	1E-09	2E-09	1E-08	1E-05
2 (both RHR HX avail)	1E-07	2E-07	1E-06	9E-04

The highest frequency, beyond-DBA LOCA condition reflected in Table 4-3 is the case where there is no RHR HX cooling, though three trains of RBCU cooling are available. This condition has an estimated frequency of 6E-07/yr. In contrast, the Oconee IPE predicts that the traditional DBA (large LOCA) will occur with a frequency of 9E-04/yr. Per Table 4-3, the IPE further predicts that the traditional DBA combined with loss of a single train of RHR HX cooling (single failure) will occur with a frequency of approximately 1E-05/yr.

4.3 Summary

Generic results indicate that for both BWRs and PWRs, the unavailability of recirculation core cooling will increase the total CDF values by two orders of magnitude. The breakdown of the impact of the unavailability of recirculation is illustrated in Table 4-4.

Table 4-4: Distribution of Expected Risk Associated When Recirculation Core Cooling is Unavailable

Accident Sequence Type	Percentage of Total Expected Risk with Recirculation Core Cooling Unavailable	
	BWR	PWR
LOCA	7%	91%
Transient	93%	7%
Other	0.3%	2%

For both reactor types, the unavailability of recirculation cooling has the greatest CDF impact on the LOCA and transient accident classes. For BWRs, the risk is centered on the transients whereas, for PWRs, the risk is centered on LOCAs. These results illustrate that the potential loss of NPSH margin associated with non-LOCA accident sequences has a significant potential impact on risk assessments. Because these results were generated from a simply screening survey, it is recommended that the PRA aspects of NPSH analysis be studied more thoroughly than was possible in this study.

It is uncertain that bounding containment conditions determined by examining DBA-LOCAs also bound conditions that exist during non-LOCA accident sequences. BWR transient sequences with SRV/ADS flows entering the suppression pool at a submerged elevation have potentially more severe bounding conditions than a LOCA. In BWR transient sequences, where RHR cooling is lost but core makeup is still provided by HPCI until battery depletion, the containment conditions become much more extreme. The more extreme conditions could affect PRA results where credit was taken for use of HPCI cooling prior to battery depletion.

It is recommended that regulatory guidance be extended to address risk important non-LOCA accident sequences. Specifically, the question of whether or not LOCA sequences adequately bound containment conditions for NPSH analysis should be investigated more thoroughly than was possible in this study. The question of whether or not the loss of NPSH margin can significantly impact the time of events in severe accidents, thus increasing the predicted risk should also be addressed.

5.0 DETAILED NPSH REVIEW AND OVERPRESSURE ANALYSIS

NPSH analyses for one BWR plant was reviewed in detail using information currently available at SEA. Since considerable data was available at SEA on the Duane Arnold Energy Center (DAEC) plant, it was reviewed in depth. Note that Duane Arnold was selected as the reference plant for the BWR ECCS strainer blockage study, NUREG/CR-6224 [12], and during the drywell debris transport study (DDTS) [13], a MELCOR containment input model was developed for Duane Arnold.

The documents and resources available at SEA for this review included:

- The Duane Arnold response to GL 97-04 [14]
- Plant NPSH Calculation for the RHR Primary Pump, MC-40B [15]
- FSAR
- IPE
- NUREG/CR-6224 Calculations
- DDTS MELCOR Input Model

This review and associated confirmatory analysis support the discussions in Section 2 regarding the need for additional clarification to existed regulatory guidance.

The DAEC plant has two systems taking suction from the suppression pool that are applicable to GL 97-04, i.e., CS system and the RHR system. The CS system consists of two independent loops with one CS pump in each loop and with a single strainer on each loop. The RHR system consists of two independent loops with two pumps in parallel in each loop. Each RHR loop contains one RHR heat exchanger and takes suction through a single suction strainer. The RHR service water is provided by two independent loops for each RHR heat exchanger. In addition, DAEC plant has an HPCI system taking suction from the suppression pool following an injection stage. The HPCI system is applicable to concerns regarding maintaining adequate NPSH during a high-pressure transient sequence.

5.1 Summary of Duane Arnold Responses to GL 97-04

The DAEC response to GL 97-04 was reviewed for any inconsistencies relative to regulatory guidance. The responses to the five requests for additional information asked of the plant and SEA comments are:

1. Specify the general methodology used to calculate the head loss associated with the ECCS suction strainers.

The response provided several specific points regarding their calculational methodology. These included:

- **Minimum absolute containment pressure (consisting of both non-condensible partial pressure and vapor partial pressure) at the containment spray temperature was used to calculate available NPSH.**

- Minimum operating level reduced by 1 foot to account for water holdup in the drywell was used.

- The vapor pressure term was the saturation pressure at torus water temperature with the temperature determined from a transient analysis considering the initial conditions, decay heat, and heat removed by the RHR heat exchangers.

- The friction loss term included a suction strainer, the suction piping and components, with the friction analysis based on clean commercial steel piping. Sensitivity calculations were performed to determine the effect of aging on the friction factor but the effects were not included in the reported NPSH numbers. The strainer head loss was analytically determined assuming 50% of the holes were blocked (analytical method not provided). **These strainer head losses were 1.66 ft at 3200 GPM for the CS strainer and 0.53 ft at 6500 GPM for the RHR strainer.**

2. *Identify the required NPSH and the available NPSH.*

NSPH data was provided for both the CS and RHR pumps at both maximum and minimum torus cooling conditions. Their new analysis included time-dependent NPSH analysis and in this analysis the CS and RHR pumps were assumed to operate at runout flow conditions for 30 minutes after the LOCA and then were assumed to throttle back to rated flow. The RHR results assumed that both pumps were running. Further, the analyses were performed at two different initial torus water temperatures. The initial containment pressure used in the analyses was 0.5 psig.

Their reported NPSH values for worst case conditions, i.e., minimum torus cooling and an initial torus temperature of 95°F and an initial containment pressure of 0.5 psig, are repeated in Table 5-1.

Table 5-1:Duane Arnold NPSH Values for Worst Case Conditions

	CS System (1 pump/loop)	RHR System (2 pumps/loop)
At Runout Flow (< 30 min)		
Flow per Pump (GPM)	4500	6500
Torus Water Temperature (°F)	161	161
Containment Spray Temperature (°F)	148	148
Containment Pressure (psig)	2.095	2.095
Available NPSH (ft)	27.1	27.5
Required NPSH (ft)	22.0	11.0
NPSH Margin (ft)	**5.1**	**16.5**
At Rated Flow (> 30 min)		
Flow per Pump (GPM)	3100	4800
Torus Water Temperature (°F)	201	201
Containment Spray Temperature (°F)	180	180
Containment Pressure (psig)	6.766	6.766
Available NPSH (ft)	28.3	27.5
Required NPSH (ft)	16.4	10.4
NPSH Margin (ft)	**11.9**	**17.1**

Note that the results reproduced in Table 5-1 are for worst-case containment thermal hydraulic conditions associated with minimum torus cooling; but these results were not the lowest NPSH margins in the DA response. The lowest NPSH margins were 2.2 and 13.6 ft for the CS and RHR systems, respectively. The reason the lowest NPSH values do not correspond to the worst-case conditions, as the values normally would, is that these values were calculated using the actual containment pressures rather than the atmospheric pressure considered acceptable in the SRP. Further, note that 2.095 and 6.766 psig of containment pressure corresponds to 4.8 and 15.6 ft-water, respectively. This is explored further in the accompanying SEA analysis.

3. *Specify whether the current design-basis NPSH analysis differs from the most recent analysis reviewed and approved by the NRC for which a safety evaluation was issued.*

The NRC issued its Safety Evaluation of the DAEC on January 23, 1973. The current design basis NPSH analysis differs from the original NRC-approved licensing basis analysis only in that errors in the original analysis have been corrected. The methodology has not changed. The errors were found during a 1997 review in connection with the redesign of the ECCS suction strainers. The errors corrected in the original analysis included non-conservative flow rates, incorrect piping configurations, non-conservative torus water temperature, and incorrect strainer head loss. The NPSH values reported in the DAEC response to

GL 97-04 correspond to the new corrected analysis; however, the DAEC response did not state whether the friction losses went up or down as a result of correcting these errors.

4. *Specify whether containment overpressure (i.e., containment pressure above the vapor pressure of the sump or suppression pool fluid) was credited in the calculation of available NPSH. Specify the amount of overpressure needed and the minimum overpressure available.*

Containment overpressure was credited in the calculation of available NPSH. An overpressure credit of 1.3 psi was required for the core spray during rated flow conditions at the time of maximum pool temperature. The predicted containment pressure was 6.3 psig.

5. *When containment overpressure is credited in the calculation of available NPSH, confirm that an appropriate containment pressure analysis was done to establish the minimum containment pressure.*

General Electric performed the original containment response analysis. A new analysis is in progress in connection with the design of the new ECCS suction strainers.

5.2 SEA Evaluation of the Duane Arnold Responses

The DAEC methodology of using the minimum containment pressure and the NPSH margins reported in the response clearly does not agree with regulatory guidance found in either RG 1.1 or SRP 6.2.2. However, the NPSH margins (per SRP guidance) can be calculated by reducing the reported NPSH values by an amount equivalent to the reported containment gage pressures. These are shown in Table 5-2. Note that the NPSH values, calculated without containment overpressure, correspond to regulatory guidance that specifies the use of atmospheric pressure and that the values for the CS system at rated flow is a negative 3.7 ft-water (1.6 psi).

Table 5-2: Comparison of NPSH Margins With and Without Overpressure

	CS		RHR	
Pumping Rates	**With**	**without**	**With**	**Without**
Runout Flow	5.1	0.3	16.5	11.7
Rated Flow	11.9	-3.7	17.1	1.5

The DAEC response contains little information for validating their maximum suppression pool temperatures. The response does state that the most limiting case occurs during the long term transient following the design basis LOCA when one core spray and one RHR pump will be running continuously. Based on SEA confirmatory MELCOR calculations (discussed in the next section), the DAEC maximum pool temperature of 201 °F is a reasonable number, in that, it appears to have been calculated with conservative assumptions. Further, their static suction head of minimum torus water level reduced by one foot to account for water holdup seems reasonable. The distance between the pump suction and the minimum torus water level, ΔH, was provided in the plant calculation, MC-40B [15] as 11.85 ft, therefore the value used in their analysis would be 10.85 ft.

SEA believes that the DAEC strainer head losses were seriously underestimated. The DAEC strainer head losses were determined analytically in 1982 based on a perforated flat plate with 50% of the holes blocked. Their reported strainer head losses are 1.66 ft at 3200 GPM for a CS strainer and 0.53 ft at 6500 GPM for a RHR strainer. As discussed in Section 3, the strainer head losses should be based on experimental data.

SEA based our confirmatory analysis on the DAEC strainer head loss on a BWROG measured head loss for a truncated cone strainer [11]. In this test, a truncated cone with a total screen area of 18 ft^2 was tested at a flow of 10,000 GPM and a water temperature of 60 °F, and found to have a clean strainer head loss of 2 ft-water. Scaling from the measured test data to the DAEC strainer areas and flow rates is based on Equation 3-6. The strainer areas for the DAEC plant were calculated and reported in the NUREG/CR-6224 study [12] as 4.21 ft^2 per loop for the CS system and 14.6 ft^2 per loop for the RHR system. The strainer head

losses predicted using the scaling method are compared to the DAEC strainer head losses (at the same temperature) in Table 5-3.

Table 5-3: Comparison of DAEC and Scaled Strainer Head Losses

System	Strainer Area (ft^2)	Strainer Flow (GPM)	Strainer Head Losses (ft-water)			Ratio
			Scaled From Measurements		DAEC 50% Blocked	
			Clean Strainer	50% Blocked		
CS	4.21	3200	3.7	15.0	1.66	9.0
RHR	14.6	6500	1.3	5.1	0.53	9.6

The strainer head losses predicted by scaling a BWROG measured head loss are almost an order of magnitude larger than the DAEC head losses for a postulated blockage of 50%. Granted, the scaling process has an associated uncertainty that would grow with the distance of the scaling from the experimental data point, i.e., the uncertainty would likely be greater for the small CS strainer than it would be for the RHR strainer. But the RHR values should be reasonably good, especially the value for the clean strainer and the scaled-from-measurement method does provide the correct trends and it does illustrate that the DAEC analytical values were underpredicted.

Next the strainer head losses for the flow rates used in NPSH analysis were determined. Table 5-4 shows the strainer head losses determined using the maximum pool temperature from the DAEC NPSH analysis of 201 °F. These head losses will increase slightly at colder pool temperatures. The DAEC dependency upon overpressure increased significantly using these new head loss numbers.

Table 5-4: Strainer Head Losses for NPSH Analysis

System and Flow Rate	Strainer Head Losses (ft-water) At Pool Temperature of 201°F	
	Clean Strainer	50% Blocked
CS		
3100 GPM Rated Flow	3.4	13.5
4500 GPM Runout Flow	7.1	28.5
RHR – 1 Pump Running		
4800 GPM Rated Flow	0.67	2.7
6500 GPM Runout Flow	1.2	4.9
RHR – 2 Pumps Running		
9600 GPM Rated Flow	2.7	10.8
13000 GPM Runout Flow	4.9	19.8

The DAEC response did not provide direct data for pressure losses in the piping; however, approximate numbers were deduced from their NPSH analysis using Equation 3-4. Once the term ΔP_f was computed, the DAEC reported strainer head loss values (adjusted for flow rate differences) were subtracted to get just the piping pressure losses. These piping friction losses are given in Table 5-5.

Note that the RHR numbers, for one-pump running in Table 5-5, are numbers scaled down (by the square of the flow velocity) from the two-pump numbers and this, of course, assumes that all of the flow transverses the same piping when either one or two pumps is running. The revised piping configuration was not available for SEA review but not all of the piping would be shared jointly by both pumps. Therefore, the one-pump numbers would likely be a somewhat higher than the values in Table 5-5 .

Table 5-5: DAEC Piping Friction Losses

System	Piping Friction Losses (ft-water) At Pool Temperature of 201°F	
	Rated Flow	Runout Flow
CS	3.0	7.8
RHR – 2 Pump Running	4.2	8.5
RHR – 1 Pumps Running (Scaled Down)	1.0	2.1

For comparison, the RHR piping friction loss calculated in plant calculation MC-40B was 3.6 ft-water given a one-pump rated flow of 4800 GPM. A piping configuration error was found and corrected since the 1970 MC-40B calculation, but the old 3.6 number is much higher than this new estimate of 1.0 ft-water and the old calculation did not appear to have any built-in conservatism. In conclusion, SEA suspects that the current friction piping losses are not conservative, especially in light of the fact that surface aging effects were not included. Note that a rusted surface is 2 to 4 times as rough as a clean steel surface and that rust can increase the friction factor on the order of 40%.

To estimate DAEC dependency on overpressure, given the higher and more realistic strainer and piping friction losses discussed above, SEA prepared best-estimate temperature-dependent NPSH curves for the CS system at rated flow and the RHR system at rated flow with one and two pumps running. These curves, presented in Figures 5-1, 5-2, and 5-3, respectively, are based on the strainer and piping friction losses shown in Table 5-6. The strainer losses in Table 5-6 are the 50% blocked strainer numbers derived for Table 5-4. The piping friction losses deduced from the DAEC data for rated flow conditions were doubled and the DAEC calculated aging corrections were included.

Table 5-6: SEA's Best-Estimate Strainer and Piping Friction Losses

Type of Loss	Strainer and Piping Friction Losses (ft-water) At Pool Temperature of 201 °F and at Rated Flow Conditions		
	CS	RHR 1 Pump	RHR 2 Pumps
Strainer – 50% Blocked	13.5	2.7	10.8
Clean Piping	6.0	2.0	8.4
Aging Correction	0.3	0.2	0.4
Total	19.8	4.9	19.6

As shown in Figure 5-1, SEA's best estimate NPSH margin remains positive for suppression pool temperatures below 204 °F, when based on a one-atmosphere containment pressure. Further, at the maximum pool temperature of 201 °F reported by DAEC, the NPSH margin was 1.9 ft-water. Therefore, SEA's confirmatory analysis indicates that the RHR system operating with one primary pump will have an adequate NPSH margin at all pool temperatures following a LOCA.

Figure 5-1 also illustrates the NPSH margin predicted by literally using the suppression pool vapor pressure for the containment pressure in Equation 3-4, as clarified in SRP 6.2.2, instead of atmospheric pressure. When the vapor pressure was used, the NPSH margin was nearly constant and negative at all pool temperatures. Note that when the vapor pressure is used for the P_s term in Equation 3-4, the NPSH margin then becomes dependent only upon the static pressure and the friction loss term, which vary only slightly with water density. Further note that the NPSH margin predicted using the vapor pressure and the margin predicted using atmospheric pressure become equal at a pool temperature of 212 °F. Thus, using the pool

Figure 5-1: NPSH Dependency on Suppression Pool Water Temperature

One RHR Pump Running at Rated Flow

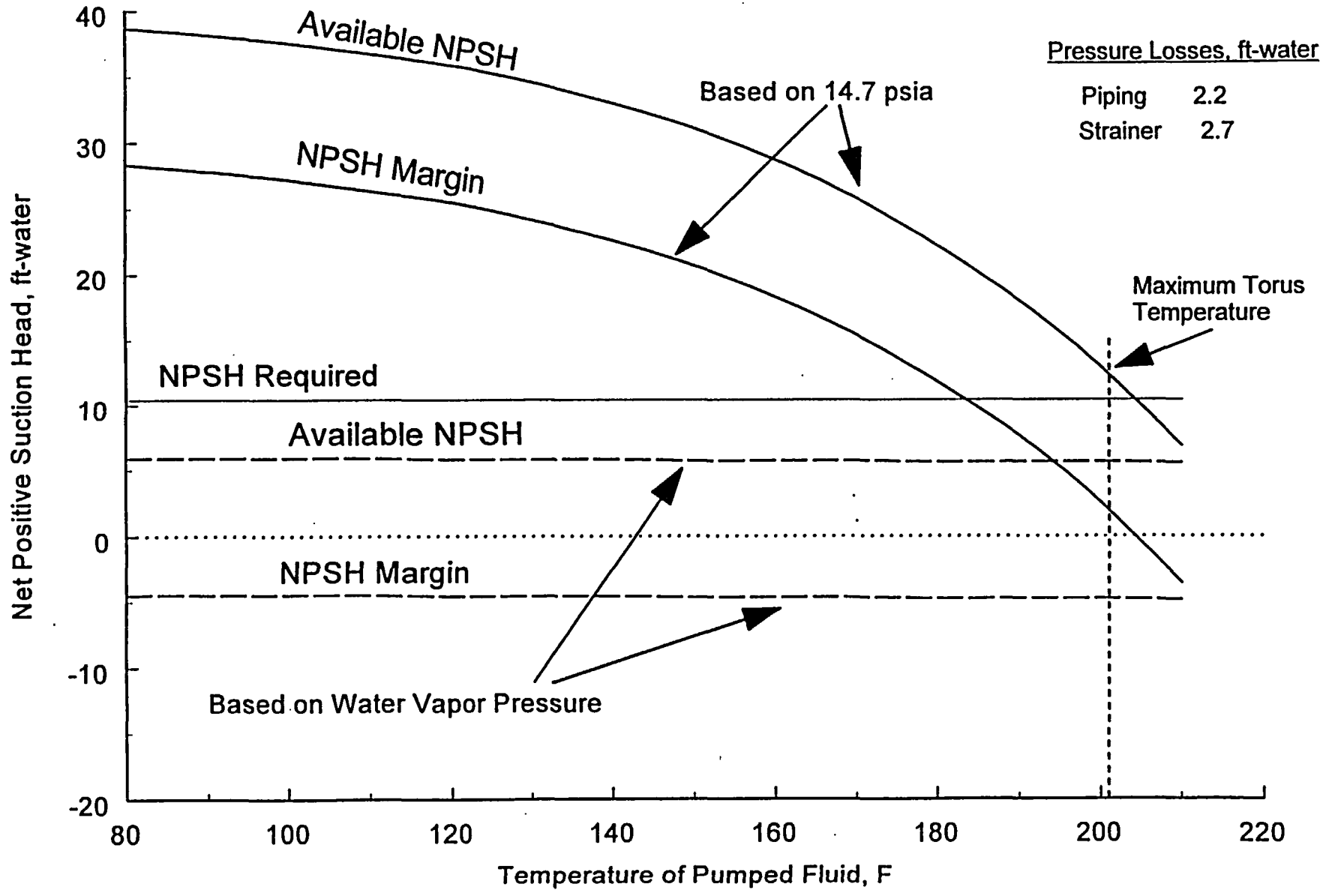


Figure 5-2: RHR NPSH Dependency on Suppression Pool Water Temperature

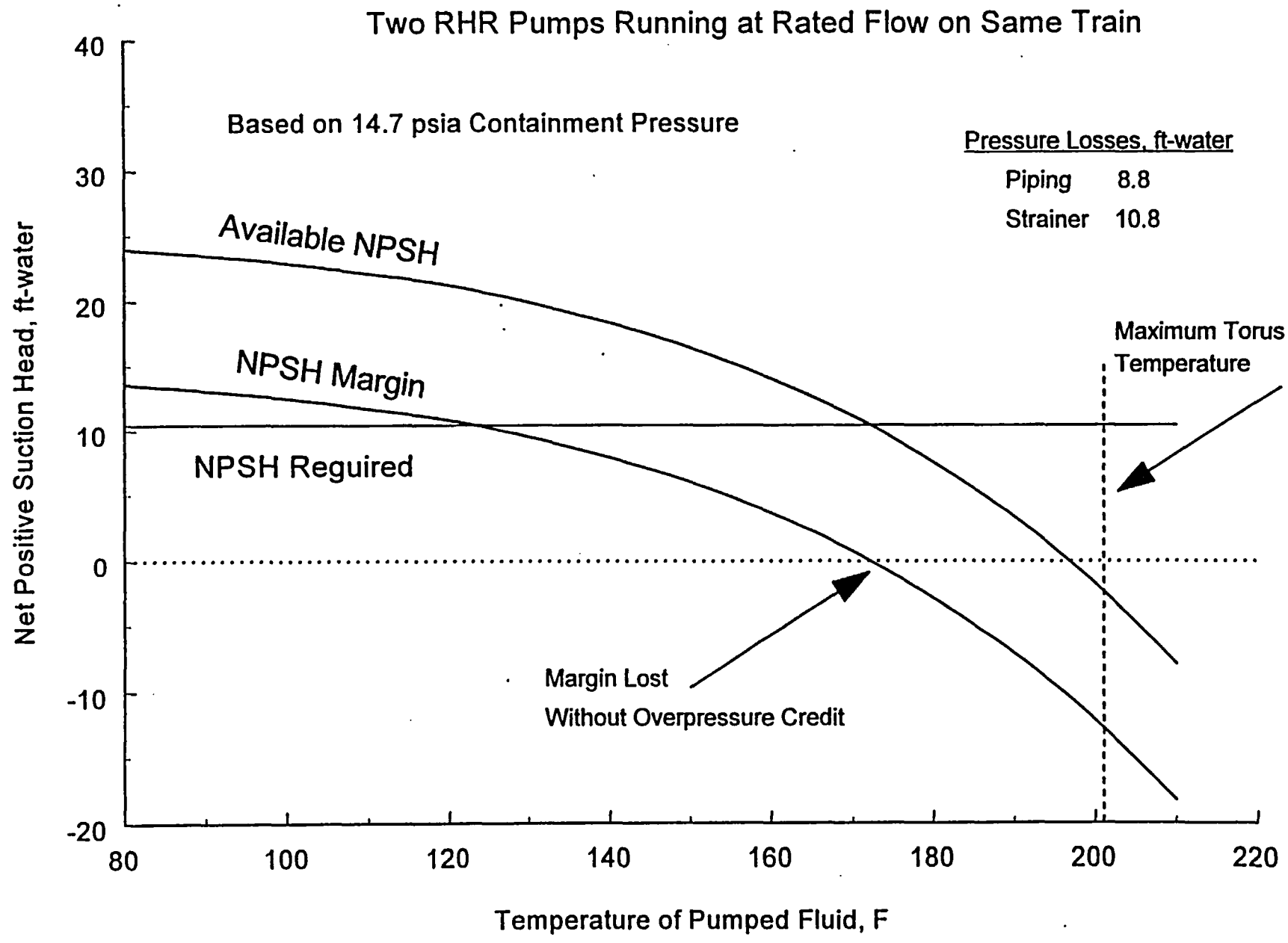
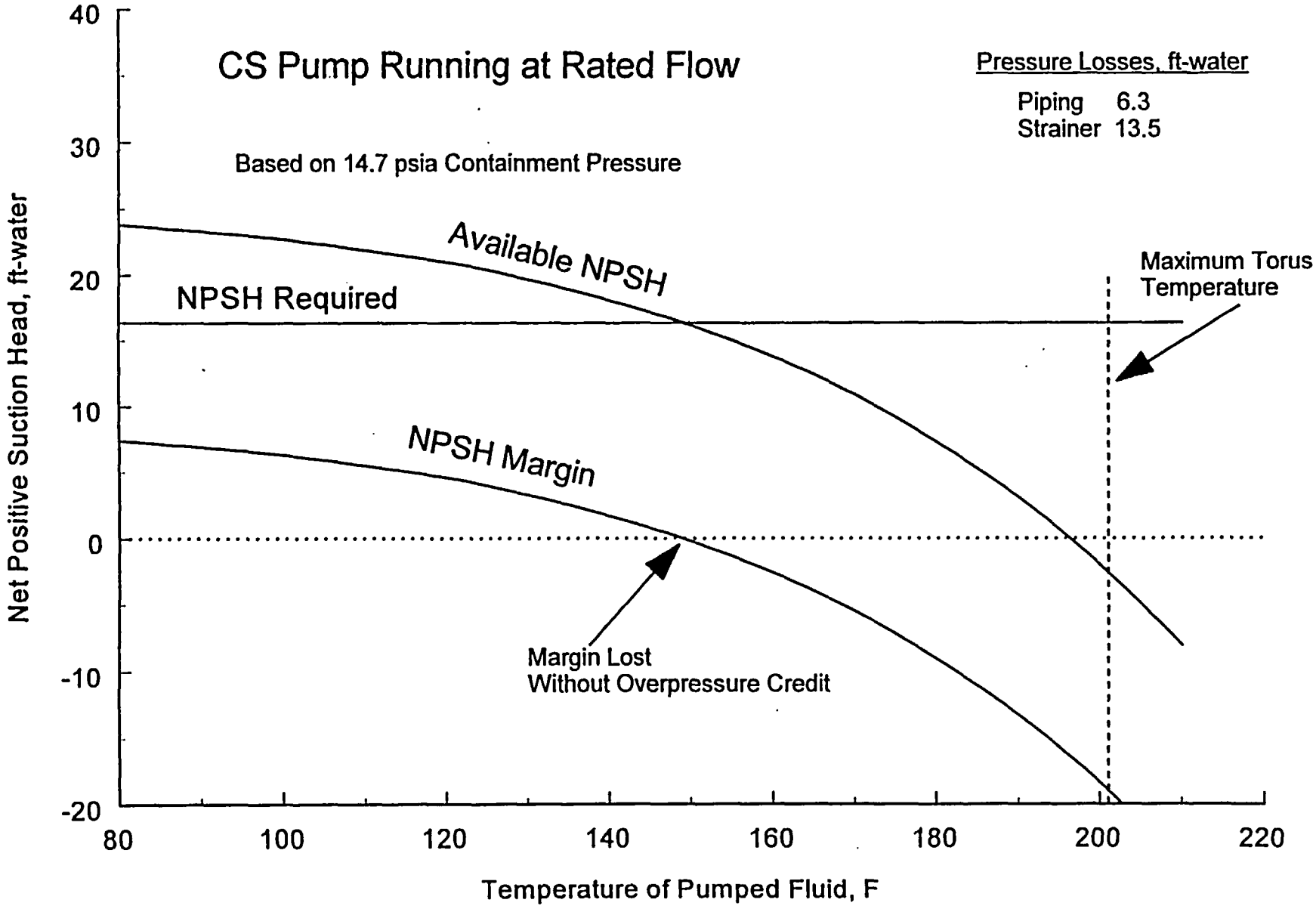


Figure 5-3: CS NPSH Dependency on Suppression Pool Water Temperature



temperature vapor pressure in NPSH analysis is tantamount to specifying that the NPSH analysis must assume the boiling temperature at one atmosphere as the maximum pool temperature.

If the RHR pump were running at the runout flow rate and 50% strainer blockage, rather than the rated flow, adequate NPSH margin without overpressure could not be assured because the friction losses would increase with the square of the flow rate. The multiplier for this increase would be 1.83 (i.e., 6500/4800 squared) effectively increasing the total friction losses from 4.9 to 9.0 ft-water. This increase is greater than the spare margin of 1.9 ft-water.

Now consider the situation when two RHR pumps are running at rated flow, as shown in Figure 5-2. In this scenario, adequate NPSH margin would not be assured for pool temperatures over 172 °F. The NPSH margin at 201 °F is a negative 12.8 ft-water corresponding to an overpressure need of 5.6 psig.

The CS system needs even more overpressure than does the RHR system primarily because of its much smaller strainer. The rated flow of 3100 GPM must pass through the 4.21 ft^2 CS strainer (only 2.1 ft^2 when 50% blocked). The NPSH margin goes to zero in Figure 5-3 at a pool temperature of 149 °F and the margin at 201 °F is a negative 19.0 ft-water corresponding to an overpressure need of 8.3 psig.

The overpressure needs for DAEC per SEA's confirmatory calculations are summarized in Table 5-7. SEA's estimate of needed overpressure credit was 7 psi higher than the corresponding DAEC number for the CS system. This increase was due primarily to an increased and more realistic estimate for the 50% blocked strainer head loss. The next step is to determine if there is reason to believe that this amount of overpressure would exist.

Table 5-7: Summary of Overpressure Credit Needed To Ensure Adequate DAEC NPSH Margins

System (at Rated Flow)	NPSH Margin at Maximum Pool Temperature of 201 °F (ft-water)	Overpressure Credit Needed (psig)
CS	-19.0	8.3
RHR with 1 Pump Running	1.9	0
RHR with 2 Pumps Running	-12.8	5.6

DAEC stated that the minimum containment pressure was taken as the partial pressure of the non-condensable gases in the drywell and torus plus the partial pressure of the water vapor assumed at saturated conditions. Further, the temperature of the water vapor and non-condensable gases was assumed equal to the containment spray temperature (i.e., the RHR heat exchanger outlet temperature). Their predicted containment pressure at rated flow conditions was 6.77 psig.

SEA did not find the DAEC overpressure analysis adequate because the analysis was overly simplified and did not consider all forms of containment cooling, such as heat transfer to the structures, and other time-dependent processes. SEA performed time-dependent analysis with the system level code, MELCOR, to illustrate the systems and processes involved in determining the containment pressure. These calculations are discussed in Section 5.3.

5.3 SEA Confirmatory Time-Dependent Overpressure Analysis

SEA undertook a series of time-dependent analyses to further clarify the potential for relying on containment overpressure for ensuring appropriate NPSH for ECC and containment heat removal pumps. These calculations are intended to illustrate the importance of the various systems and processes involved in determining potential containment overpressure. The containment pressure is strongly dependent upon the effectiveness of many of these systems and processes, e.g., the pressure is strongly related to the

suppression pool temperature. As discussed in Section 2, regulatory guidance in regard to determining containment overpressure relative to long-term recirculation cooling is generally lacking. In fact, there does not even appear to be a clear definition for long-term recirculation overpressure. These calculations, performed for the DAEC plant, provide insights into this issue that will hopefully contribute to the development of a procedure for correctly determining a conservative overpressure.

5.3.1 Calculational Model for Duane Arnold

The MELCOR code uses a lumped sum approach to calculating thermal hydraulic behavior, i.e., control volumes connected by flow pathways. Each volume may contain a gravitationally separated pool of water (either single or two-phase) and an atmosphere consisting of any combination of water vapor, suspended water droplets or noncondensible gases. The shape of the control volumes, specified with a volume-altitude table, determine the water level within the volume given the pool mass, temperature, and pressure. The pool and the atmosphere are each individually treated by equilibrium thermodynamics both having the same pressure but different temperatures. Noncondensible gases are modeled as ideal gases with temperature dependent specific heat capacities. Hydrodynamic materials move through the flow pathways connecting the volumes. Heat is transferred between the atmosphere and the pool within a volume and between the atmospheres and pools and their surrounding surfaces implemented as heat structures. Methods are available for simulating the variety of ECCS systems and their time-dependent behavior.

Detailed containment nodalization is not needed for running long-term containment cooling calculations; therefore, the DAEC containment was implemented using three volumes, i.e, the drywell, wetwell, and the connecting downcomer/vent system. Because of the downcomer/vent system, the drywell and wetwell operate at somewhat different pressures, temperatures, and vapor content, these were modeled separately. Correctly modeling the downcomer/vent system is important because this system provides the separation between the drywell and wetwell that causes them to behave differently. Further, the downcomer/vent models impact the suppression pool surface level as water is forced into and out of the downcomer pipes. The vacuum breakers were modeled as an integral part of the downcomer/vent system. The model included a containment leakage pathway designed to leak 5% of the containment atmosphere at the containment design pressure. The volumes were initialized with a 0.75 psig pressure and temperatures of 135 °F and 95 °F for the drywell and wetwell, respectively.

The structures included in the input model included the drywell outer wall, the reactor pedestal and shield wall, the drywell floor, the downcomer/vent piping, the suppression pool torus, and miscellaneous steel. The torus was connected to a stagnant air-filled compartment surrounded by thick concrete walls to simulate the reactor building torus room heat transfer. If the torus room were actually ventilated following a LOCA, then this mode of cooling the suppression pool was not included in the model. No information was found to support to torus room ventilation; however, SEA was unable to determine that this was not possible.

A single volume RCS model was implemented to provide RCS flows to the containment and to function as a repository for decay heat. A flow pathway from the RCS to the drywell simulated a large LOCA and another pathway from the RCS into the suppression pool simulated the SRVs for high-pressure sequences and the ADS for low-pressure transient sequences.

Decay heat power was sourced directly into the RCS water using either a conservative-estimate or a best-estimate correlation. The conservative-estimate decay heat correlation was the 1979 ANS standard [16] with the reactor power specified as the DAEC licensing power of 1658 MWt increased by 2% for potential instrument error and another 20% as a conservative safety factor (in accordance with Appendix K of 10 CFR Part 50). The best-estimate decay heat correlation was adapted from a best-estimate risk assessment of the LaSalle Unit 2 nuclear power plant [17] performed by Sandia for the NRC with the reactor power level specified as the licensing power of 1658 MWt.

Models were included for applicable ECCS (i.e., RHR, LPCS, and HPCI systems) and for drywell coolers. These models are illustrated in Figure 5-4. The one train of the RHR provides water from the suppression pool to the containment sprays when sprays are activated. The containment sprays in the DAEC plant have

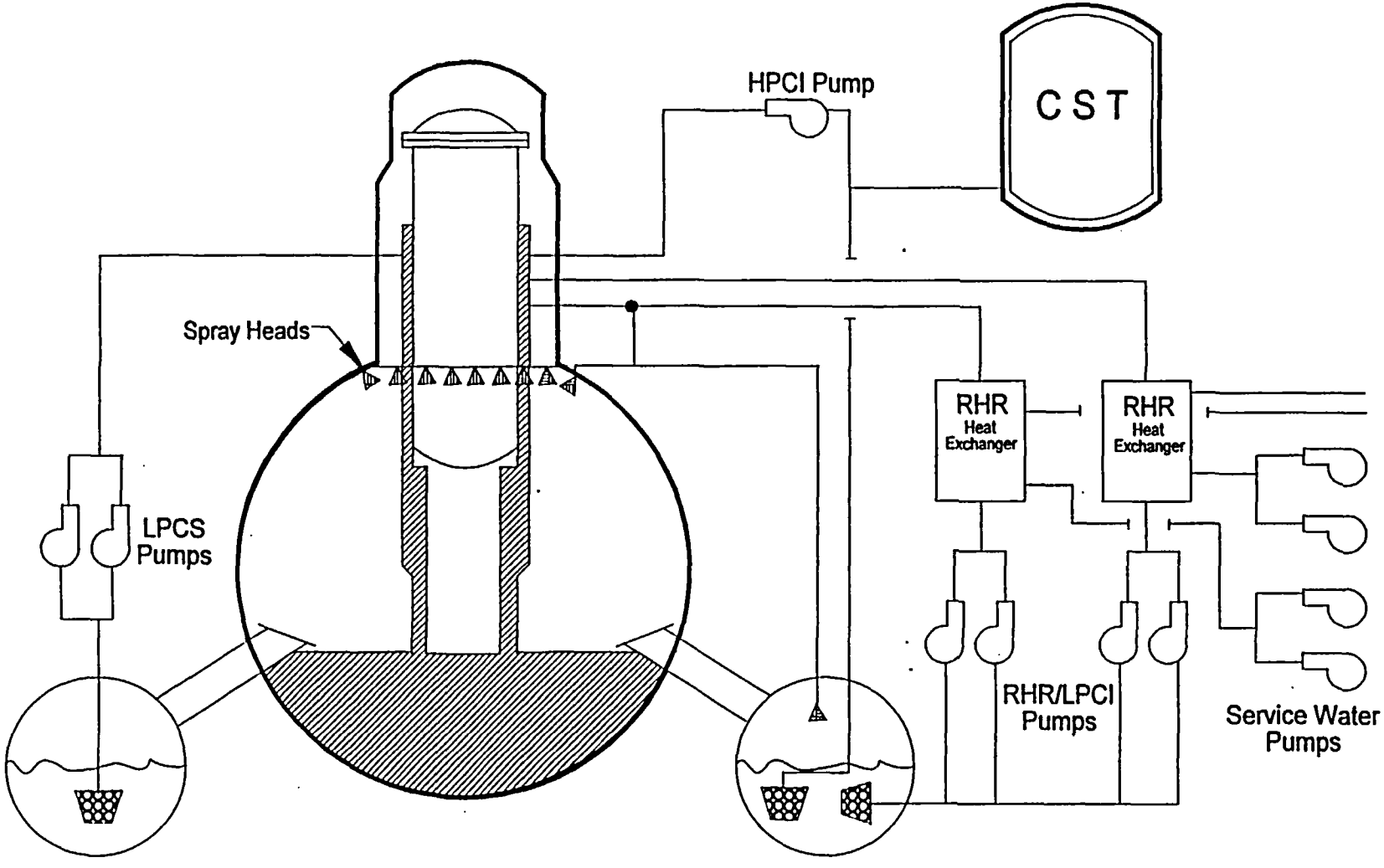


Figure 5-4: Duane Arnold MELCOR Analytical Model

a train to the wetwell where 5% of the spray flow may be used to cool the wetwell atmosphere. The other RHR train provides water to the RCS when used. When the sprays are not operated, both RHR trains can be aligned to the RCS. The LPCS system simply pumps water from the suppression pool to the RCS when used. For high-pressure transient sequences, the HPCI system pumps a 3000 GPM of water to the RCS from the CST until a total of 75,000 gallons has been pumped, thereafter the HPCI draws water from the suppression pool.

5.3.2 Minimum Cooling Following a Large LOCA

A calculation was run to demonstrate the total cooling capacity of the containment. Is there some minimum containment overpressure that would exist for any accident sequence? To answer this question, a large LOCA calculation was run with all installed cooling capability assumed to operate at maximum capacity. The systems and models assumed in this calculation included:

- Large LOCA break
- Two trains of LPCS at rated flows
- Both RHR heat exchangers operating with the runout flow of 13,000 GPM (two pumps) on the primary side and 5400 GPM (two pumps) on the service water side and with a best-estimate overall heat transfer coefficient for the heat exchanger
- Service water temperature of 35 °F
- One train of the RHR aligned to the containment sprays with 5% of the spray flow aligned to the wetwell
- Drywell coolers operating
- Best-estimate decay heat
- Containment structures active
- Containment leakage active

The pertinent results of this calculation are illustrated in the Figures 5-5 through 5-8, showing the containment pressures, vapor mole fractions, temperatures, and heat loads, respectively. The calculations were run for a 72-hour period (note the logarithmic time scale in these figures). The containment cooling was extensive enough to cool the containment atmosphere below the initial temperature of 95°F, as well as, to condense the majority of the water vapor. Ten hours into the calculation the wetwell pressure drop below the atmospheric pressure to a negative 0.5 psia below atmospheric pressure. The drywell pressure is similar to the wetwell pressure; however, the continual cooling provided by the containment sprays kept the drywell pressure lower than the wetwell pressure. The increase in the drywell pressure after about 20 hours was due to the leakage of air back into the containment once the pressure became subatmospheric. The pressures correspond directly to the vapor in the containment. The vapor mole fractions are only about 2% after about 10 hours. The suppression pool cools to about 64°F. Most of the decay heat was removed from the containment by the RHR heat exchangers, as shown in Figure 5-8. The drywell coolers removed a lesser amount of heat from the containment but this amount approached zero after about 10 hours. A net heat load was initially transferred into the structures for the first hours, thereafter the structures transfer heat back to the atmospheres and pools.

The answer to the above question is that there is sufficient containment heat removal capability to reduce the containment pressure following a LLOCA to a pressure lower than the containment initial operating pressure. Therefore, granting an overpressure to this plant must be based on time-dependent and accident sequence-dependent pressures. The following calculations explored the potential for these time-dependent pressures.

5.3.3 Maximum Cooling Following a Large LOCA

The next series of calculations looked at containment pressures associated with the calculation of the maximum suppression pool temperature. The maximum pool temperature, reported in the DAEC GL 97-04 response, was 201°F corresponding to their most limiting long-term recirculation cooling sequence with

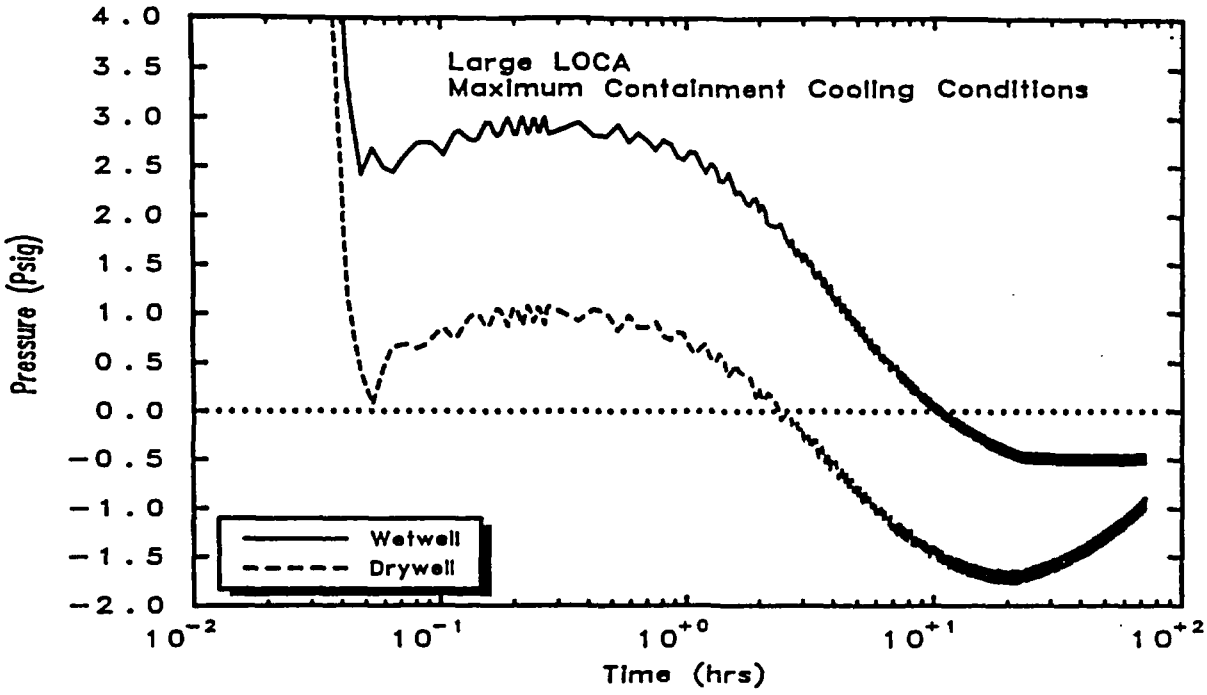


Figure 5-5: Gage Pressures at Maximum Cooling

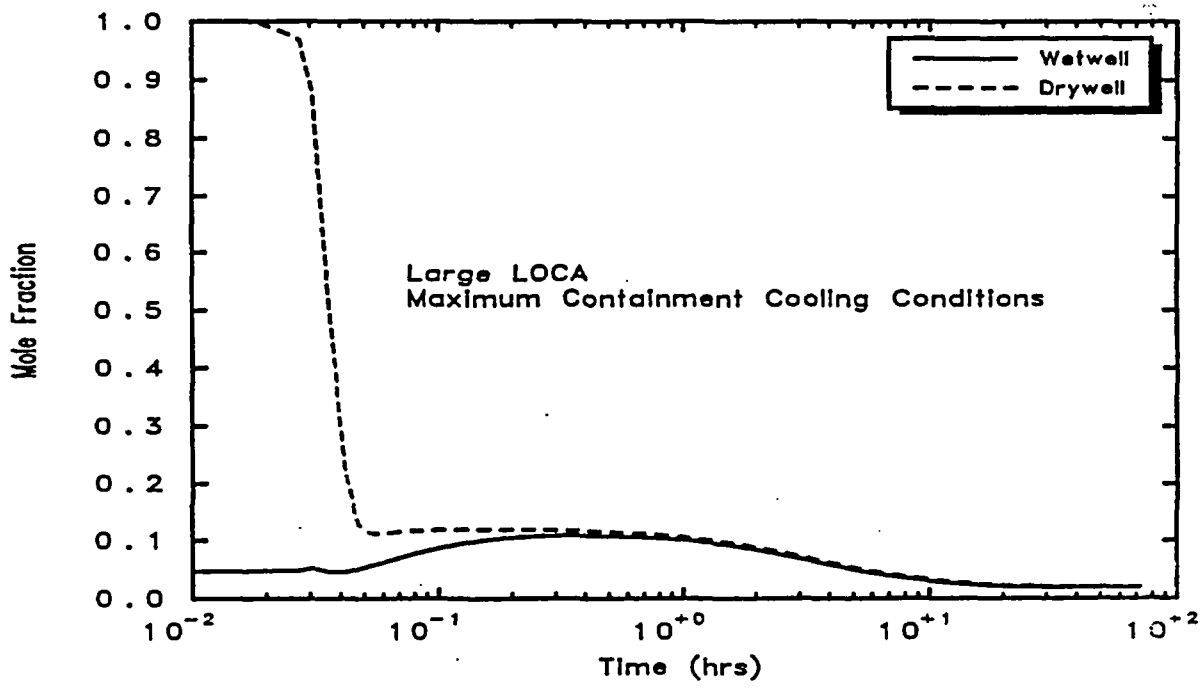


Figure 5-6: Water Vapor at Maximum Cooling

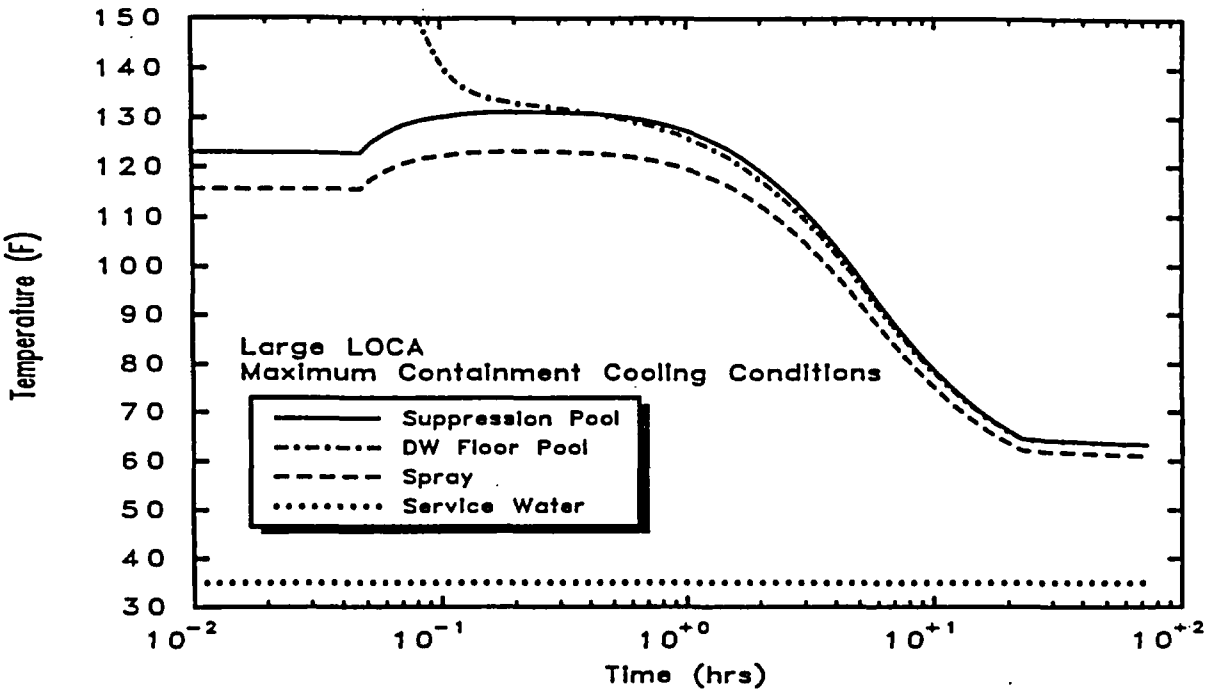


Figure 5–7: Temperatures at Maximum Cooling

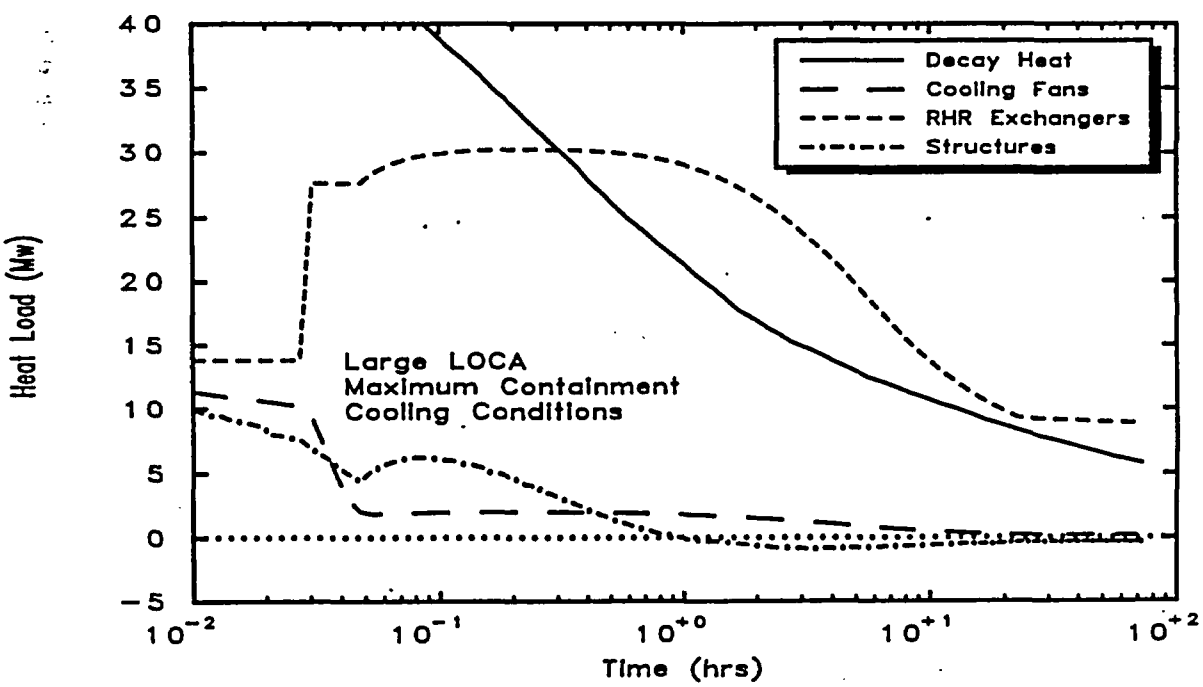


Figure 5–8: Heat Loads at Maximum Cooling

one core spray and one RHR pump running continuously following a design basis LOCA. A MELCOR simulation was able to predict this temperature by assuming the following:

- One LPCS pump supplying 3100 GPM to the RCS
- One RHR pump supplying 4800 GPM to the containment sprays
- One service water pump supplying 2400 GPM to the one RHR heat exchanger
- Service water temperature of 95 °F
- Conservative heat exchanger overall heat transfer coefficient
- Conservative decay heat power
- No containment spray to the wetwell
- No heat transfer to the structures
- No drywell coolers
- No containment leakage

A variety of results are included for this calculation to provide the reader with an overall understanding of the processes at work in these analyses. These results are found in Figures 5-9 through 5-18. The MELCOR-predicted maximum suppression pool temperature for this calculation is 201. °F which is in excellent agreement with the DAEC maximum pool temperature indicating that the same general assumptions were used. In particular, the DAEC analysis probably used a conservative decay power in accordance with Appendix K of 10 CFR Part 50, as did the MELCOR calculation.

The containment pressure, shown in Figure 5-10, peaked at 13.45 psig, whereas DAEC reported a pressure of 6.766 psig. Note that the saturation pressure for water at 201°F is 11.77 psi. The SEA gage pressure includes both the vapor pressure and an increase in the non-condensible gas pressure above atmospheric due to a higher temperature. SEA does not understand why the DAEC containment pressure is less than the suppression pool vapor pressure.

The evaporation from a water surface, as the water pool heats, is not an instantaneous process. As water evaporates, the pool surface cools, thereby slowing the rate of evaporation. Subsequently, heat from the bulk of the pool is convected to the surface to keep the process going. As a result, the vapor pressure in the wetwell atmosphere will lag behind the saturation pressure of the pool. Since this process was modeled in the MELCOR code, its effects are inherent in these calculations. For the maximum temperature calculation under discussion, the vapor pressure lag is shown in Figure 5-12. The magnitude of the pressure lag was generally about 1.5 psi as the pool heated and about 0.5 psi when the temperature of the pool peaked. The point of this discussion is that this process is not considered in simplistic containment pressure calculations and ignoring the process is not conservative.

The time-dependent terms used to calculate the available NPSH (Equation 3-4) are shown in Figure 5-15. The friction loss term is relatively low for the RHR system because only one pump is running at rated flow but the LPCS friction loss is significantly higher. The NPSH available and NPSH margins, based on the actual containment pressure, are shown in Figure 3-16, for both systems. The margins for both systems remained positive throughout the calculation when the actual containment pressure was used.

Figures 5-17 and 5-18 compare the NPSH margins, calculated by one of three containment pressure assumptions (i.e., actual pressure, atmospheric pressure, and vapor pressure at the pool temperature), for the RHR and LPCS systems, respectively. When atmospheric pressure is assumed the RHR margin remained positive but the LPCS margin was negative indicating that an overpressure credit is needed. When the vapor pressure assumption was assumed, the margins for both systems were negative throughout the calculations illustrating the impracticality of this assumption.

Although this maximum pool temperature calculation was entirely appropriate for determining the maximum pool temperature to use in the NPSH analysis, it did not determine a conservative containment pressure for use is specifying an overpressure credit because it did not model all installed methods and processes for reducing pressure. Additional calculations were run to illustrate this point. The models and

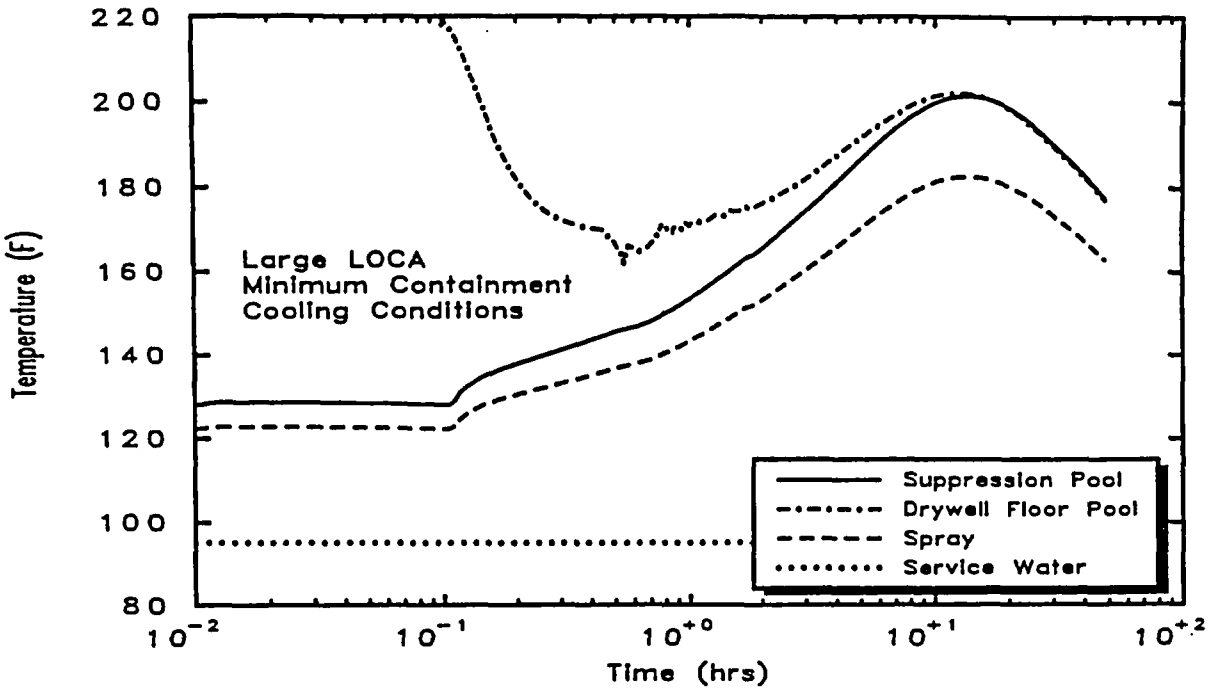


Figure 5–9: Temperatures at Minimum Cooling

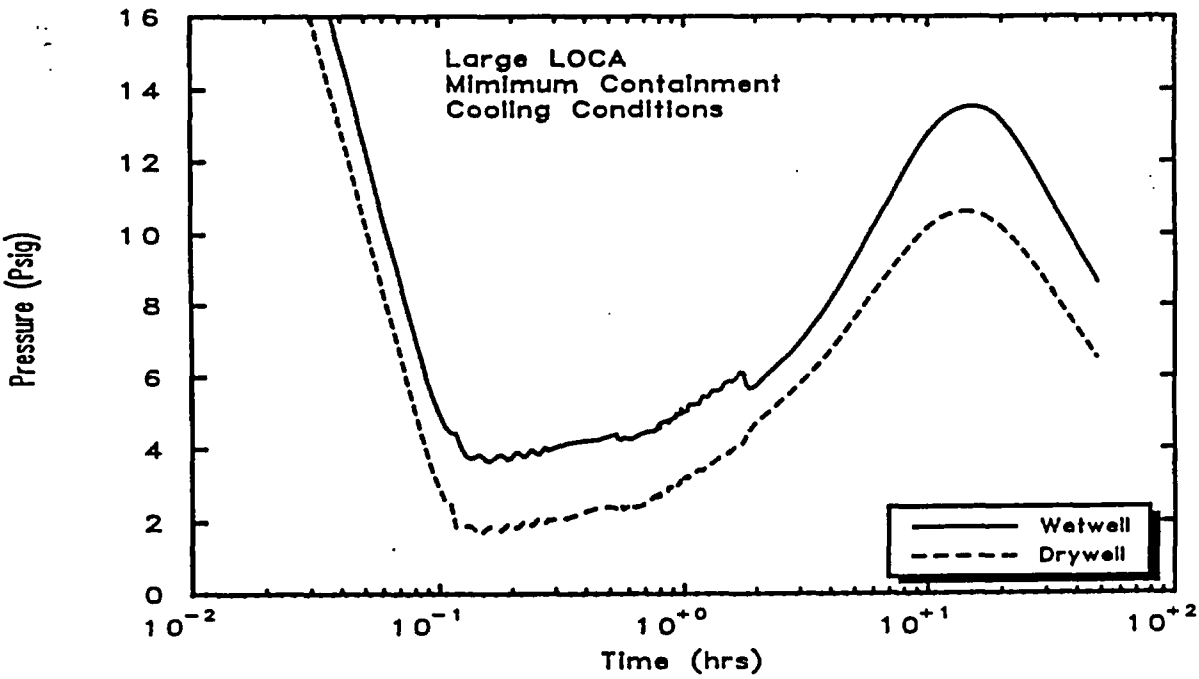


Figure 5–10: Gage Pressures at Minimum Cooling

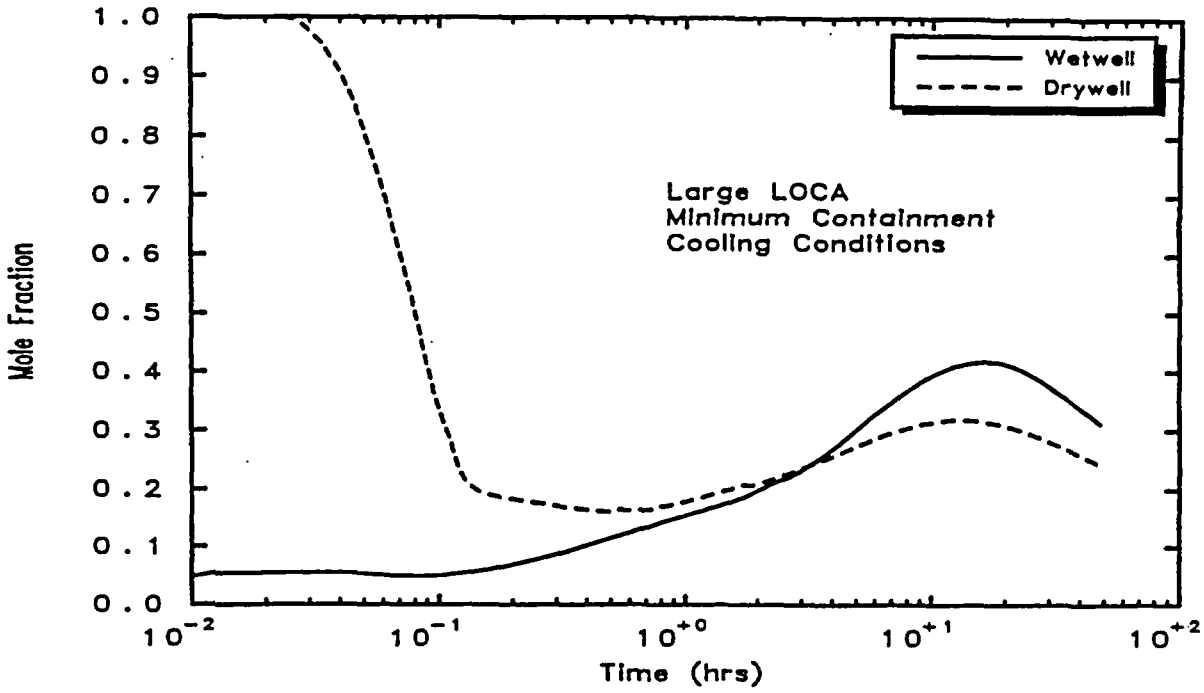


Figure 5–11: Water Vapor at Minimum Cooling

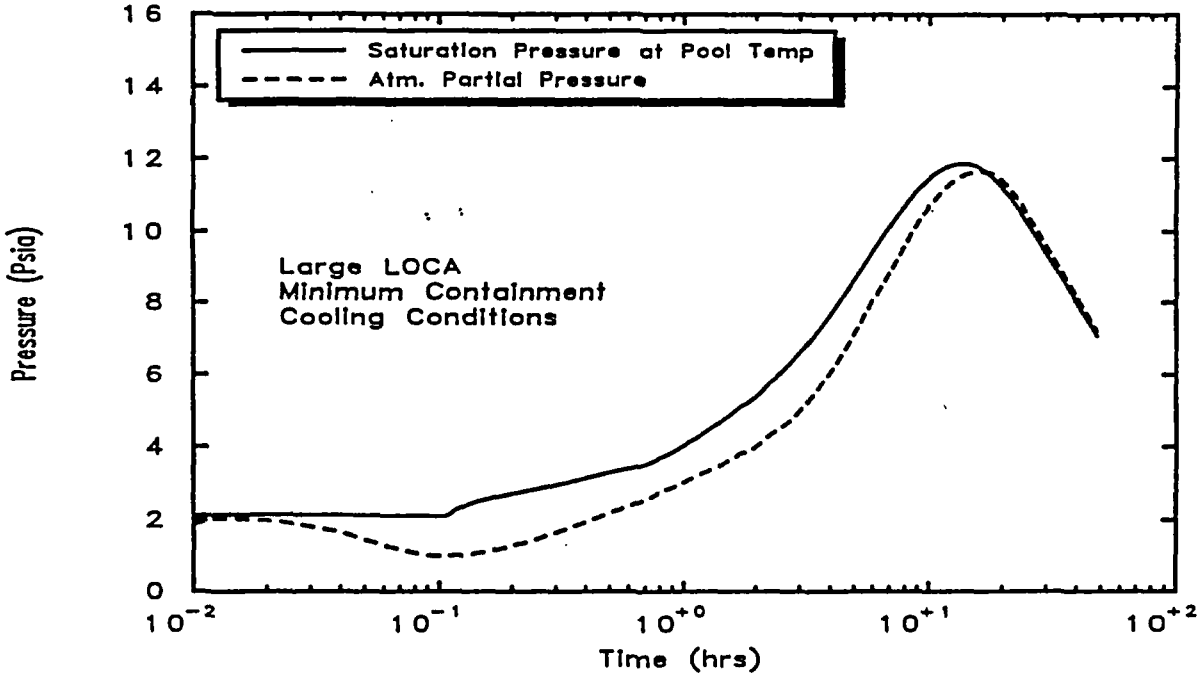


Figure 5–12: Water Vapor Pressure Lag

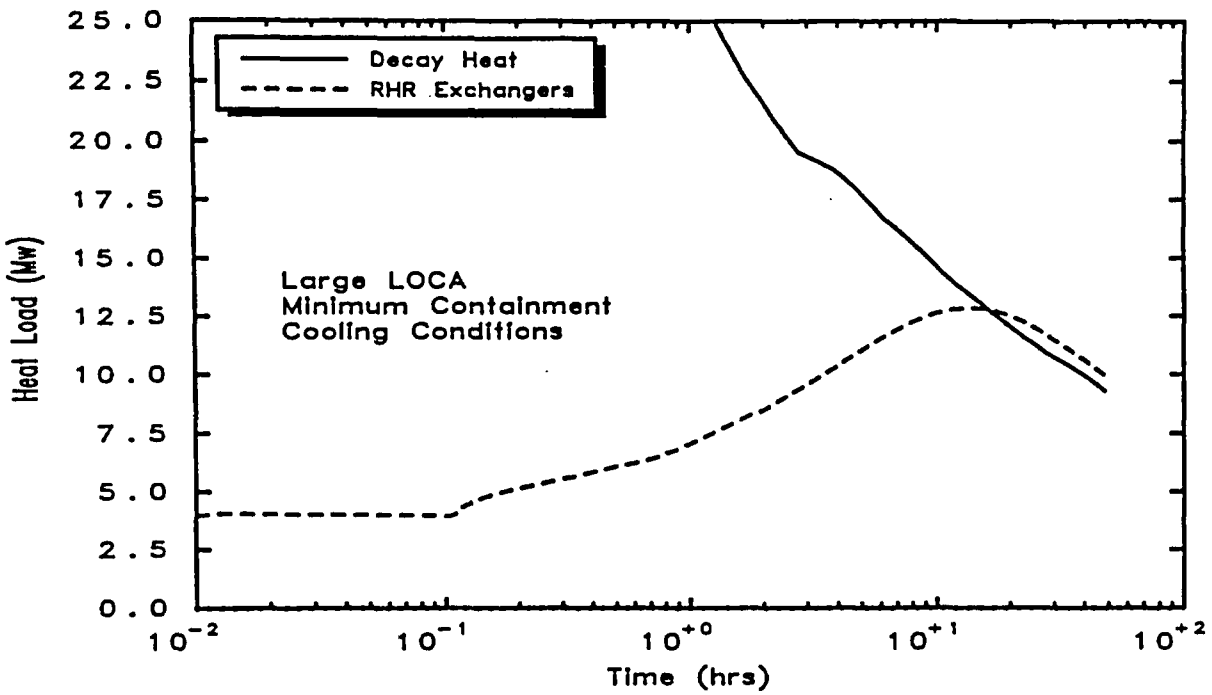


Figure 5–13: Heat Loads at Minimum Cooling

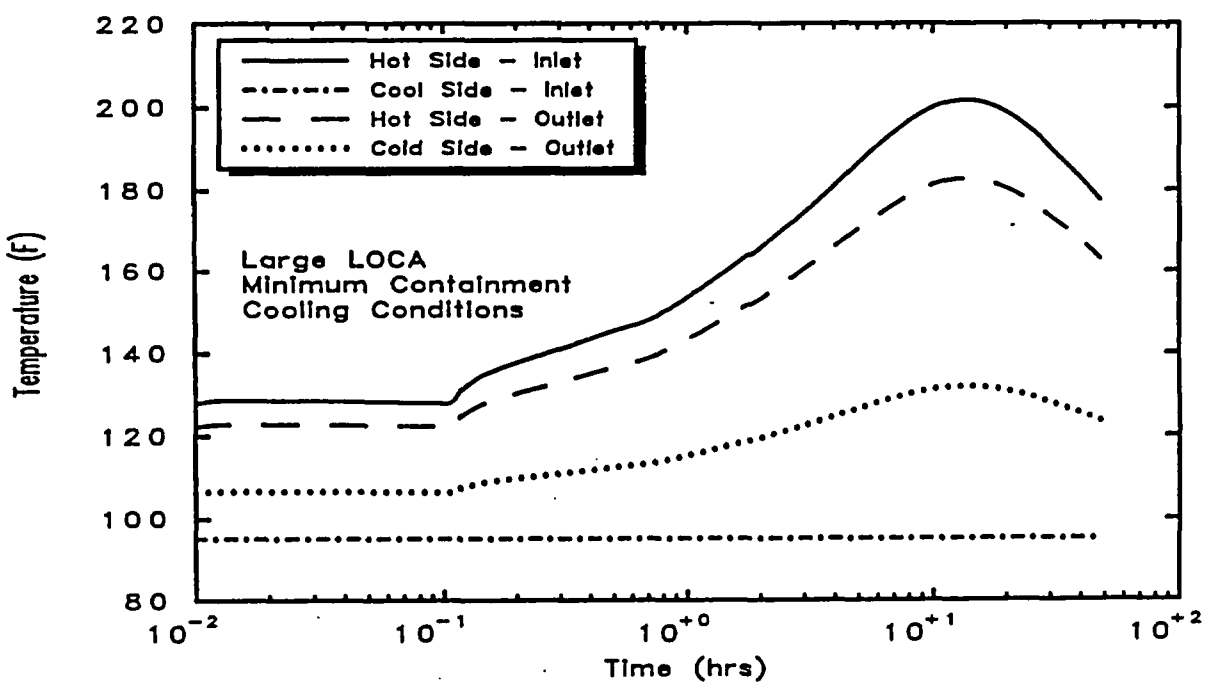


Figure 5–14: RHR Heat Exchanger Temperatures

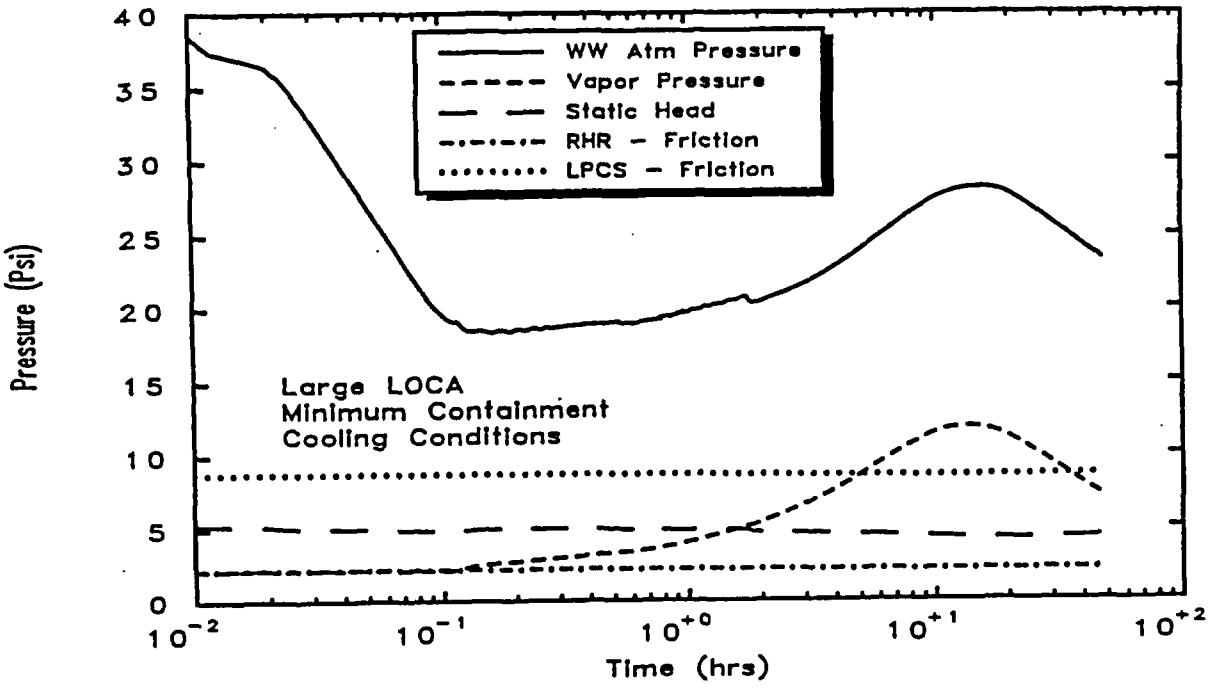


Figure 5-15: Pressure Terms in NPSH Equation

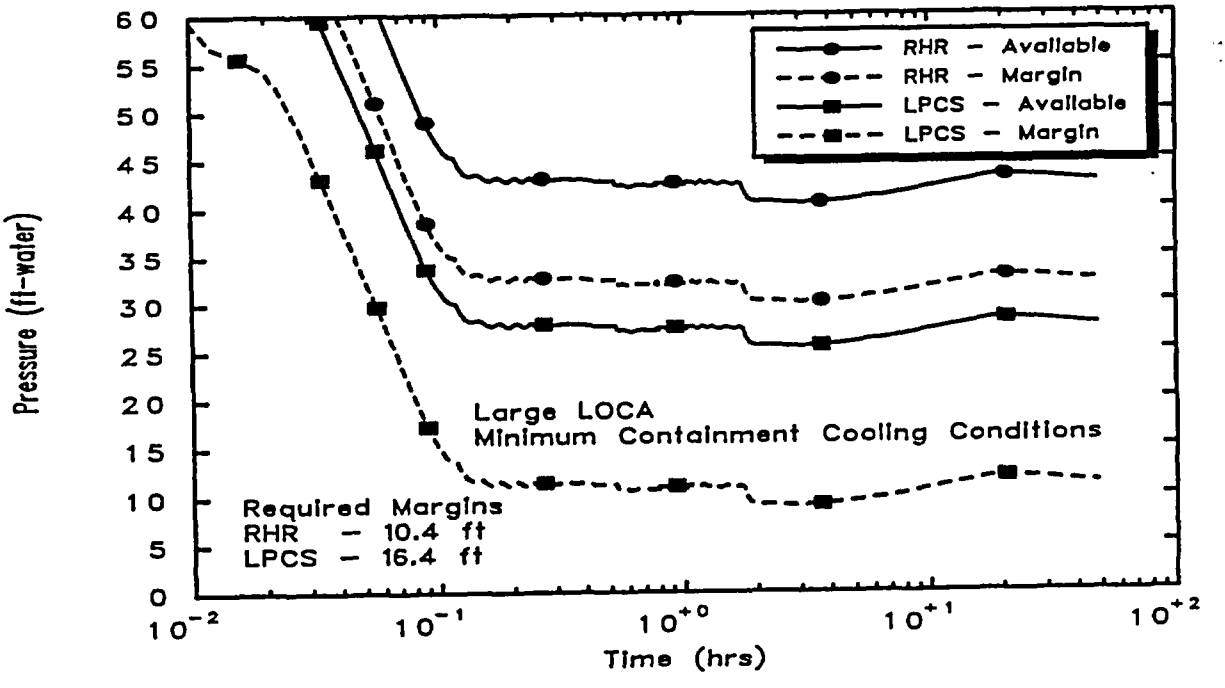


Figure 5-16: NPSH Heads Based on WW Pressure

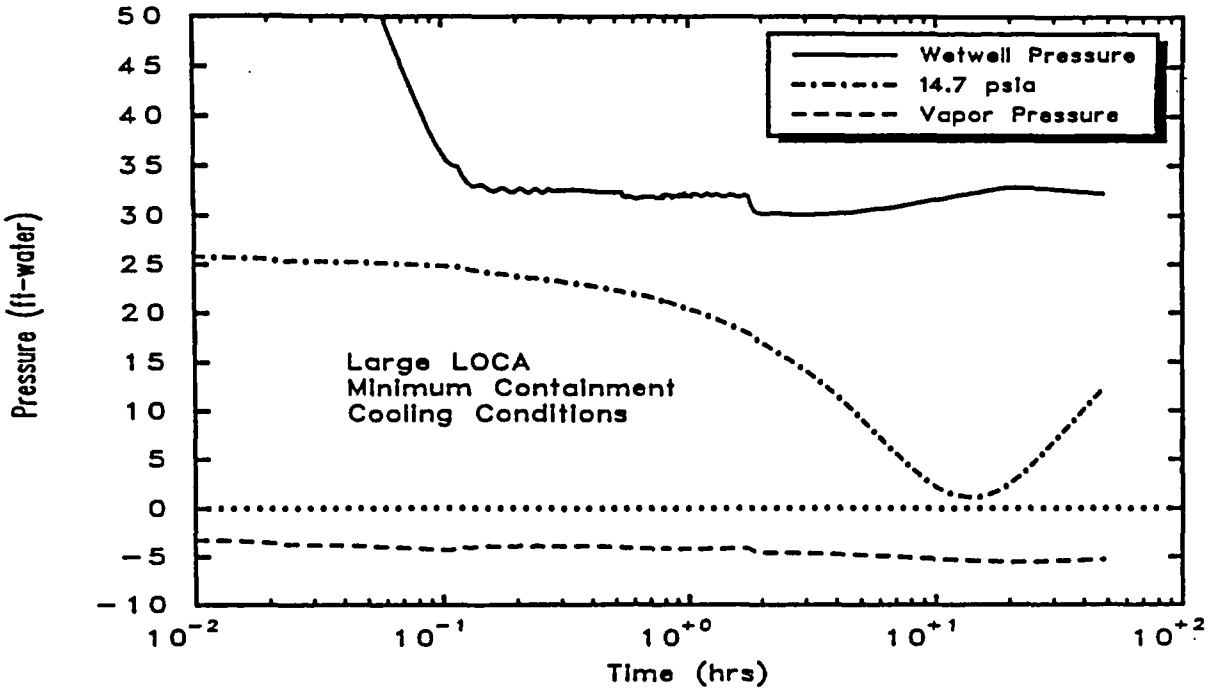


Figure 5-17: RHR Margins .vs. Pressure Assumption

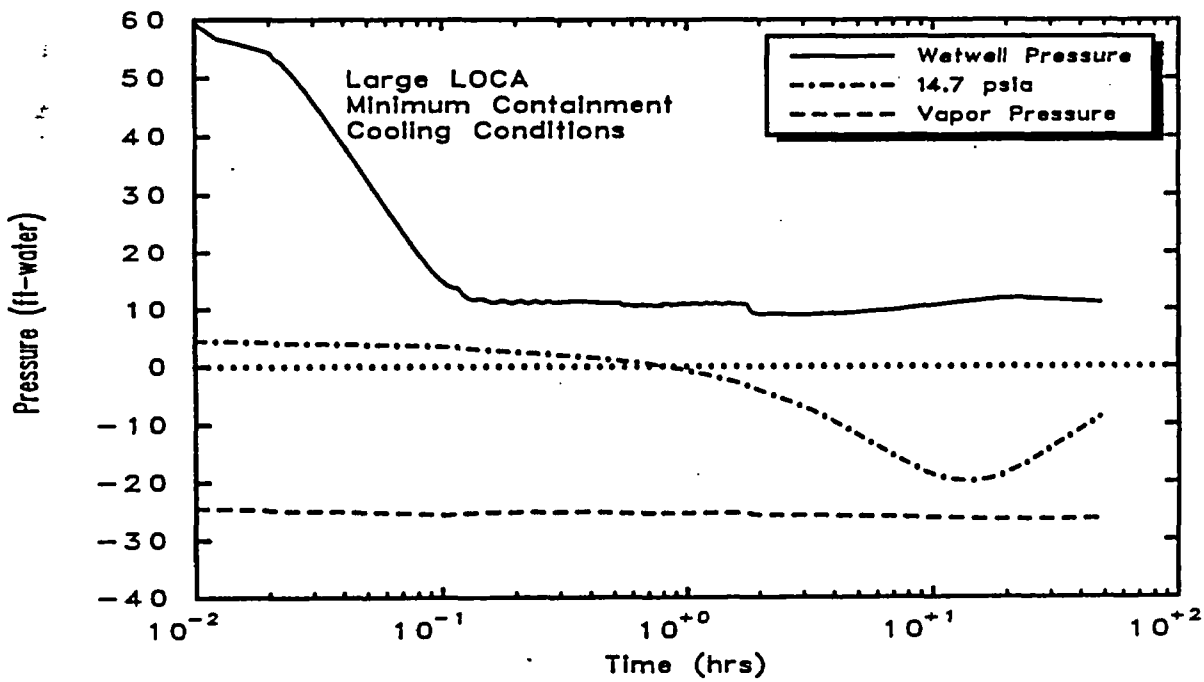


Figure 5-18: LPCS Margins .vs. Pressure Assumption

parameters assumed in these additional calculations are listed in Table 5-8. All of these calculations assumed 95 °F service water temperature.

Table 5-8: Alternate Maximum Cooling Calculations

Case No.	Flow from RCS	Decay Heat	Cont. Sprays	RHR Heat Exchanger			Cont. Struct.	DW Fan Coolers	Cont. Leak-age
				Prim. Pumps	Service Water Pumps	Heat Trans. Coef.			
1	LOCA	Cons.	100/0	1	1	Cons.	No	Off	No
2	LOCA	Cons.	100/0	1	2	Cons.	No	Off	No
3	LOCA	Cons.	95/5	1	2	Cons.	Yes	Off	Yes
4	LOCA	Cons.	95/5	1	2	Cons.	Yes	On	Yes
5	LOCA	Best	95/5	1	2	Cons.	Yes	On	Yes
6	LOCA	Cons.	Off	1	2	Cons.	No	Off	No
7	ADS	Cons.	100/0	1	2	Cons.	No	Off	No
8	LOCA	Cons.	100/0	2	2	Cons.	No	Off	No
9	LOCA	Cons.	95/5	1	1	Cons.	No	Off	No
10	LOCA	Cons.	100/0	1	1	Cons.	No	Off	Yes
11	LOCA	Cons.	100/0	1	1	Best	No	Off	No

An explanation of the parameters varied follows.

Flow from RCS All cases assumed a large LOCA except for Case 7 for which the ADS was assumed to open immediately instead of a LOCA so that the RCS flow entered the suppression pool rather than the drywell.

Decay Heat All cases except Case 5, assumed the conservative-estimate decay heat correlation discussed in Section 5.3.1. Case 5 assumed the best-estimate decay heat correlation.

Containment Sprays Three options were modeled for the containment sprays. In the first option (denoted as 100/0), 100% of one RHR train was sprayed into the containment drywell. In the second option (denoted as 95/5), 95% of one RHR train was sprayed into the drywell and 5% is sprayed into the wetwell. The third option was no containment sprays. Per the DAEC FSAR, there are two spray headers, one in the drywell and one in the wetwell and approximately 5% of the spray flow may be directed to the suppression chamber spray ring to cool any noncondensible gases collected in the free volume above the pool. Thus, the 95/5 option to determine the impact of the wetwell sprays on containment pressure.

Number of RHR Primary Pumps All cases, except Case 8, assumed one primary side pump running on the only RHR train operating. Case 8 assumed that both pumps were running.

Number of RHR Service Water Pumps These calculations were run with either 1 or 2 service water pumps running on the only RHR train operating.

Effective Heat Exchanger Heat Transfer Coefficient One of two values was used for the product of effective heat transfer coefficient and the heat exchanger area. The best-estimate value of 6.272E5 Btu/hr-°F was calculated using the log-mean temperature difference model and the FSAR RHR heat exchanger performance data. This value was adjusted so that the base case predicted the same maximum pool temperature of 201 °F as was reported by DAEC. This reduced value was 5.6E5 Btu/hr-°F and is referred to the Table 5-8 as the conservative value.

Heat Transfer of Structures. Calculations were run with and without heat transfer to the containment structures.

Drywell Coolers Cases 4 and 5 assumed that the drywell fan cooler survived the LOCA and were used to cool the containment. In all other cases, the coolers were not available.

Containment Leakage A containment leakage model was activated in four calculations. This leakage was calibrated to leak from the drywell at a rate equivalent to 5% of the containment atmosphere per day at the containment design pressure.

Pertinent results for these maximum pool temperature calculations are given in Table 5-9. These results include the maximum suppression pool temperature, the peak wetwell gage pressure, and the minimum NPSH margins for both the RHR and LPCS systems.

Table 5-9: Results for the Maximum Pool Temperature Calculations

Case No.	Maximum Pool Temperature (°F)	Peak Wetwell Pressure (psig)	Minimum NPSH Margin (ft-water)	
			RHR	CS
1	201.5	13.5	1.1	-19.8
2	196.5	11.9	4.2	-16.8
3	193.5	9.7	6.4	-14.6
4	182.3	6.4	11.6	-9.4
5	162.4	4.6	17.7	-3.4
6	197.1	13.9	4.7	-16.3
7	196.9	12.1	4.8	-16.1
8	192.5	11.7	-7.7	-13.9
9	201.5	11.5	1.8	-19.1
10	201.4	12.8	1.4	-19.5
11	196.0	11.8	4.4	-16.5

Several informative comparisons can be made from these eleven calculations, i.e., how does a particular model or parameter affect the maximum pool temperature or the peak wetwell pressure or the NPSH margins? These effects are given in Table 5-10.

A number of interesting observations can be drawn from Table 5-10. The most significant impact on the maximum pool temperature was the decay heat correlation, i.e., the conservative correlation with its 22% safety factor predicts a maximum pool temperature almost 20 °F higher than the best-estimate correlation. However, the corresponding increase in the peak wetwell pressure was a more modest 1.8 psi, although the vapor pressure increased by 2.8 psi. The use of the conservative decay heat correlation also had a substantial impact on the NPSH margins (6 ft-water).

The largest single impact on the peak wetwell pressure was due to the use of the drywell fan coolers (3.3 psi) because the coolers remove heat directly from the atmosphere. Although, the fan coolers are not a safety system and may not actually be in use following a LOCA, regulatory guidance stated that all systems capable of reducing pressure be considered in minimum pressure analyses.

It is interesting that simply aligning 5% of the sprays directly to the wetwell, as opposed to keeping all of the sprays in the drywell, had as big an impact as did turning the sprays off. A small spray flow to the wetwell can be an effective pressure suppressant. Another reason this result is important is that the possibility of aligning 5% of the sprays to the wetwell in analyses could easily be overlooked.

Table 5-10: Comparative Results for the Maximum Pool Calculations

No.	Comparison	Cases Compared		Change in Peak Pressure (psig)	Change in Maximum Temp (°F)	Change in NPSH Margin (ft-water)	
						RHR	CS
1	Conservative versus Best Estimate Decay Heat	4	5	1.8	19.8	-6.1	-6.0
2	Structures and Leakage	2	3	2.2	3.0	-2.2	-2.2
3	Leakage	1	10	0.7	0.1	-0.3	-0.3
4	Containment Sprays	6	2	2.0	0.6	0.5	0.5
5	Aligning 5% of Sprays to Wetwell	1	9	2.0	-0.1	-0.7	-0.7
6	Drywell Fan Coolers	3	4	3.3	11.2	-5.3	-5.2
7	Number of RHR Service Water Pumps	1	2	1.6	5.0	-3.0	-3.0
8	Effective Heat Exchanger Heat Transfer Coefficient	1	11	1.7	5.4	-3.3	-3.2
9	Number of RHR Primary Side Pumps	2	8	0.2	4.0	11.9	-2.9
10	LOCA or ADS	7	2	0.2	0.4	0.7	0.7
11	Largest Differential Pressure	6	5	9.4	34.6	-13.1	-12.9
12	Largest Differential Temperature	9	5	6.9	39.1	-15.9	-15.7

The concern that introducing the RCS effluent directly into the suppression pool, as opposed to the drywell atmosphere, was explored by activating the ADS model instead of the LOCA model. The concern was that when the effluent entered the suppression pool directly, the pool would absorb more of the energy, thus, enhancing the maximum pool temperature without a corresponding increase in the containment pressure. Comparison 10 in Table 5-10, however does not bear out this concern, in that, the pressure and temperature only went up by 0.2 psi and 0.4 °F, respectively. It is likely that over the long-term, sufficient equilibration takes place that it does not matter much whether the effluent enters the drywell or the wetwell. However, a word of caution is in order, this study was not conducted sufficiently enough in depth to completely dismiss this concern and overpressure credit analysis should continue to examine this concern on a case by case basis.

All of these models affected the containment overpressure and NPSH analyses to some extent. Further, the effects are not additive, i.e., an integrated analysis is required to determine the overall effects of various model options or sequence selections. Comparisons were made to determine the largest impact between cases on both the wetwell pressure and the maximum pool temperature. The largest change in peak pressure was 9.4 psi and the largest change on maximum pool temperature was 39.1 °F. While it is correct to make conservative simplifying assumptions when predicting the maximum pool temperature, the same simplifying assumptions can lead to a very incorrect assessment of the available overpressure. The issue is examined further in Section 5.4 but first we will look into the NPSH analysis associated with transient calculations.

5.3.4 Analysis of Transient Sequences

NPSH analyses are generally based on the single failure criterion following a design basis LOCA. In PRA space, recovery from certain transient sequences where core cooling is provided by a steam-driven turbine-pump, may be credited, e.g., if power is recovered before the batteries deplete. However, it is likely that these risk assessments did not examine whether or not there was adequate NPSH margin for this period of time. Note that for this type of accident sequence, where all containment cooling is lost, the thermal hydraulic conditions within the suppression pool are more severe than the typical LOCA sequence with containment cooling.

To examine this issue, two transient calculations were run to determine whether or not there would be an adequate NPSH margin for a 12-hour period. These transients were:

Station Blackout (SB) A loss of offsite power (LOSP) initiating event occurs and is followed by the failure of the emergency onsite AC sources. The reactor core is cooled by high-pressure injection from either the RCIC and/or the HPCI systems that requires DC power for its operation. The batteries supplying DC power will last 8-hours for RCIC and 12-hours for HPCI. In the thermal hydraulics model, the RCS remained at high pressure using the SRVs for pressure relief, the 3000 GPM HPCI drew water from the CST until 75,000 gallons were injected into the RCS, then the HPCI pumped from the suppression pool. All containment cooling was lost.

Loss of Power Conversion System (PCS) A loss of river water occurs as an initiating event and is followed by a non-recoverable loss of feedwater/condensate, the loss of circulating water makeup, the loss of the main condenser, the loss of emergency service water, and the loss of RHR service water. The HPCI, RCIC, and LPCI system are still available to cool the reactor core. In the thermal hydraulic model, the RCS remained at high pressure for one hour, then the ADS operated lowering the RCS pressure to containment pressures. During the first hour, the HPCI drew 75,000 gallons of water from the CST before pumping from the suppression pool. After one-hour, the reactor core was cooled by the LPCI system. All containment cooling was lost.

There are two NPSH related questions associated with these sequences.

- Is there adequate NPSH margin for the HPCI pumps to pump from the suppression pool?
- If AC power is restored to the RHR and CS systems, will there be adequate NPSH margin for their operation?

The SEA calculations address the second question and provide insights into the first question. Data needed to assess the NPSH margin for the HPCI system was not available to SEA.

Time-dependent results for the SB sequence are shown in Figures 5-19 through 5-24. These figures show the containment pressures and temperatures, heat loads, and NPSH margins. The PCS sequence results are not shown because these results were similar to the results for the SB sequence. Since all containment cooling was lost in these sequences, the containment pressures and temperatures continue to increase throughout the calculation. A portion of the decay heat was transferred into the concrete structures but not enough to stop the pressurization process.

The lag between the suppression pool saturation pressure and the wetwell vapor pressure is more pronounced in these transient calculations than it was in the maximum temperature calculations. As shown in Figure 5-19, this lag exceeds 5 psi at times.

The suppression pool temperature exceeds the atmospheric boiling temperature at 5.9 hours and at 12-hours the temperature is 267°F. **These temperatures raise the question of whether or not pumps can survive pumping water this hot.** The answer to this question was not within the scope of this study; however, the question should be examined at some point.

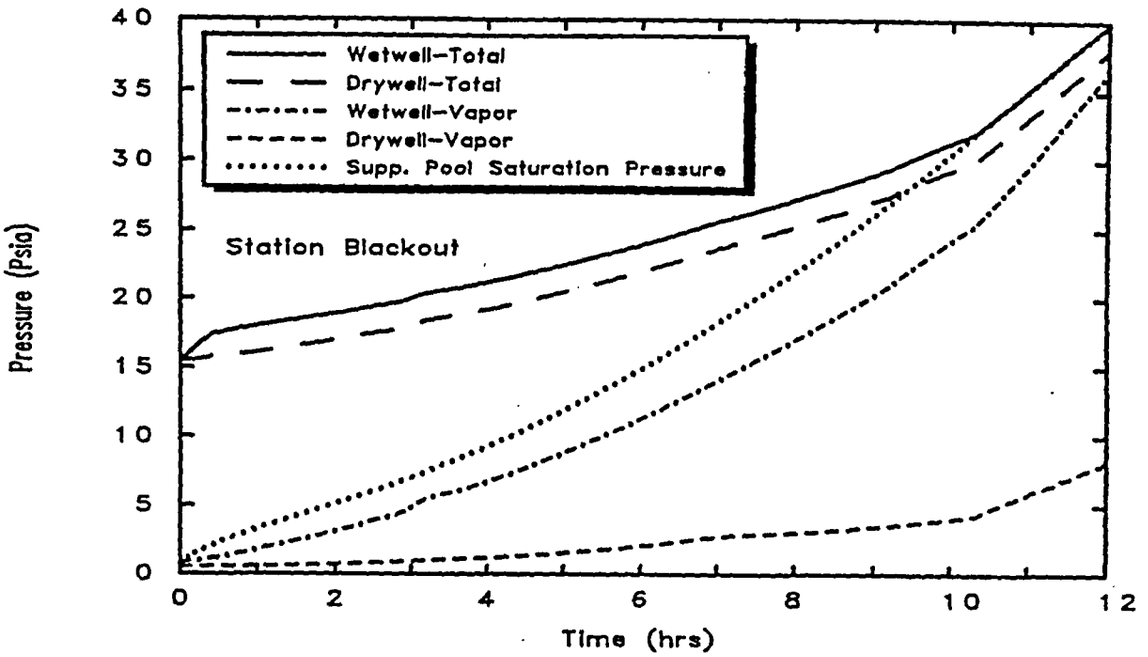


Figure 5–19: Containment Pressures

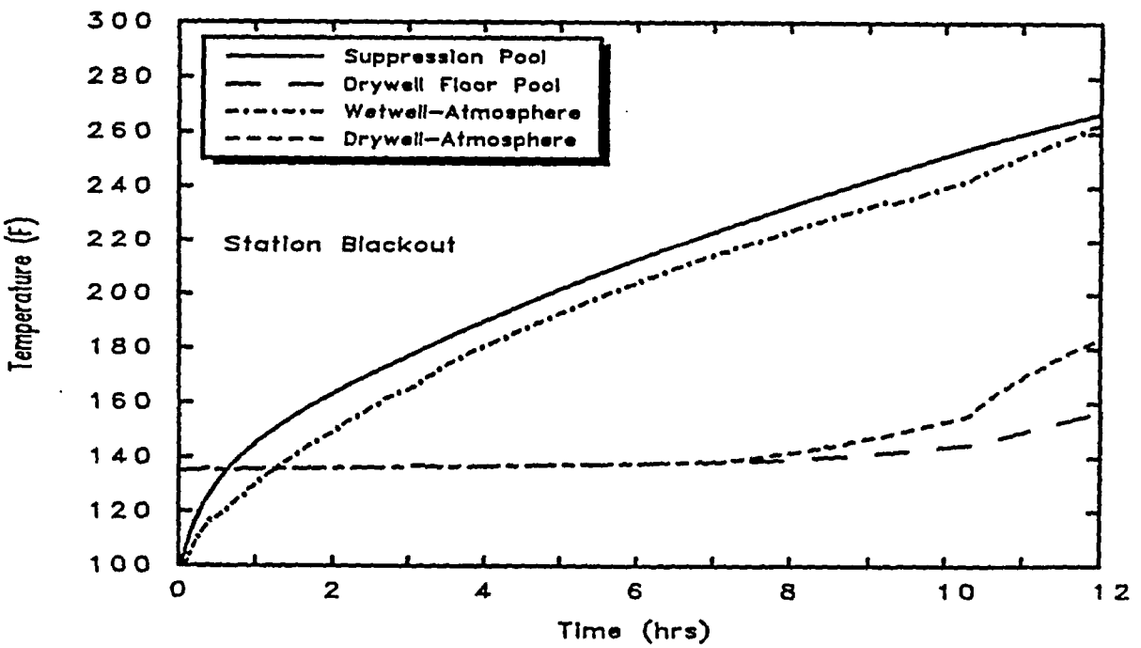


Figure 5–20: Containment Temperatures

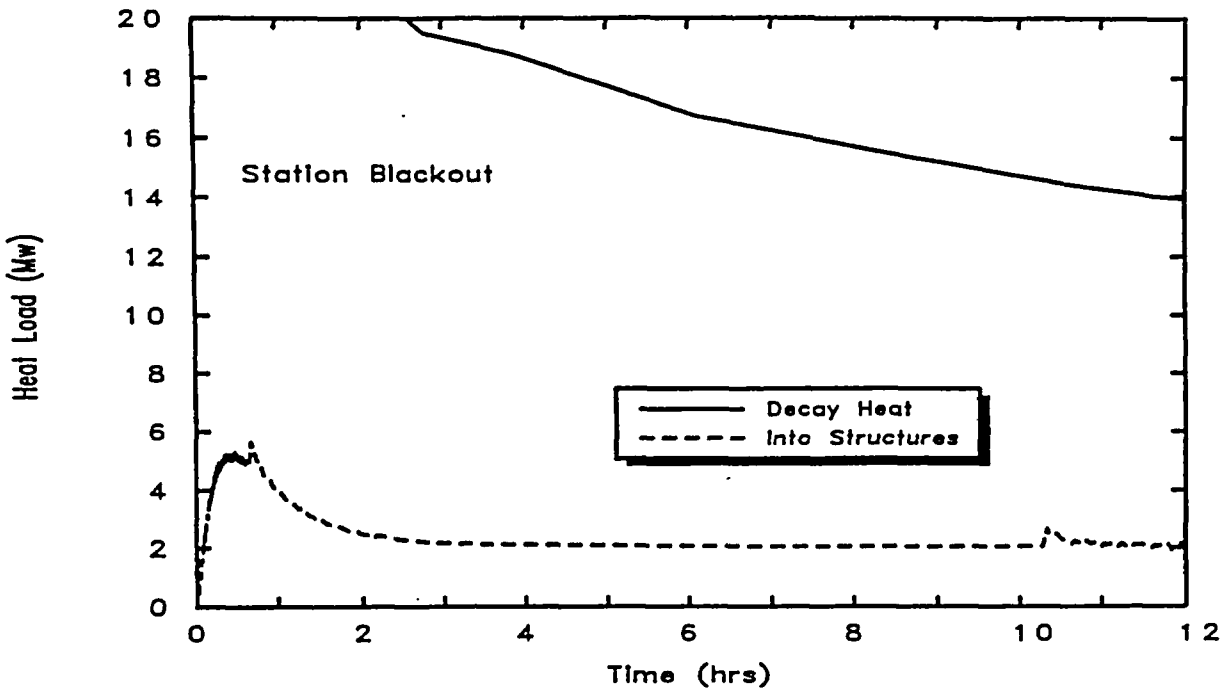


Figure 5-21: Heat Loads

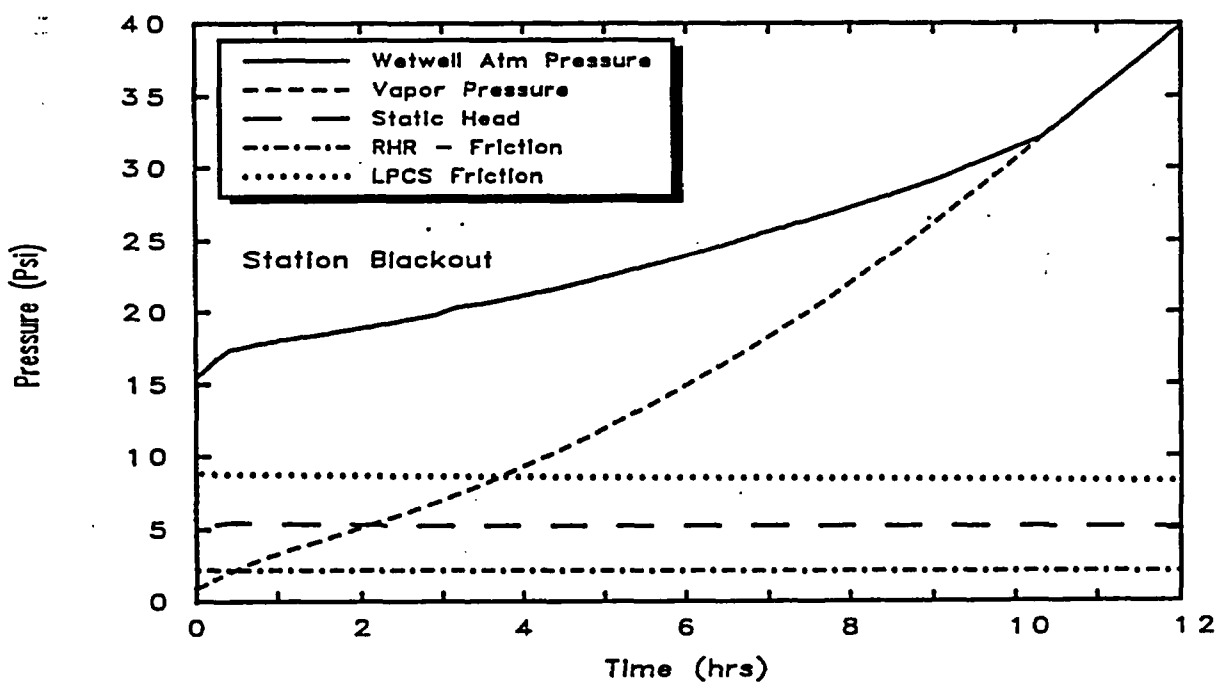


Figure 5-22: Pressure Terms in NPSH Equation

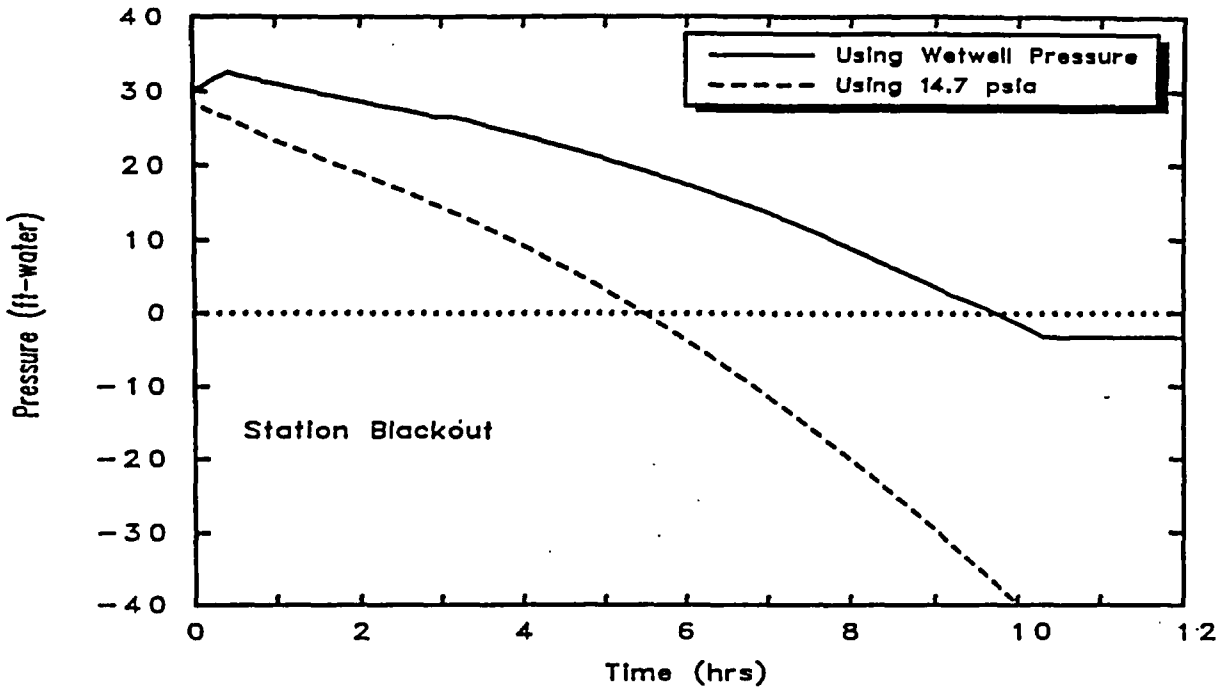


Figure 5-23: RHR NPSH Margin

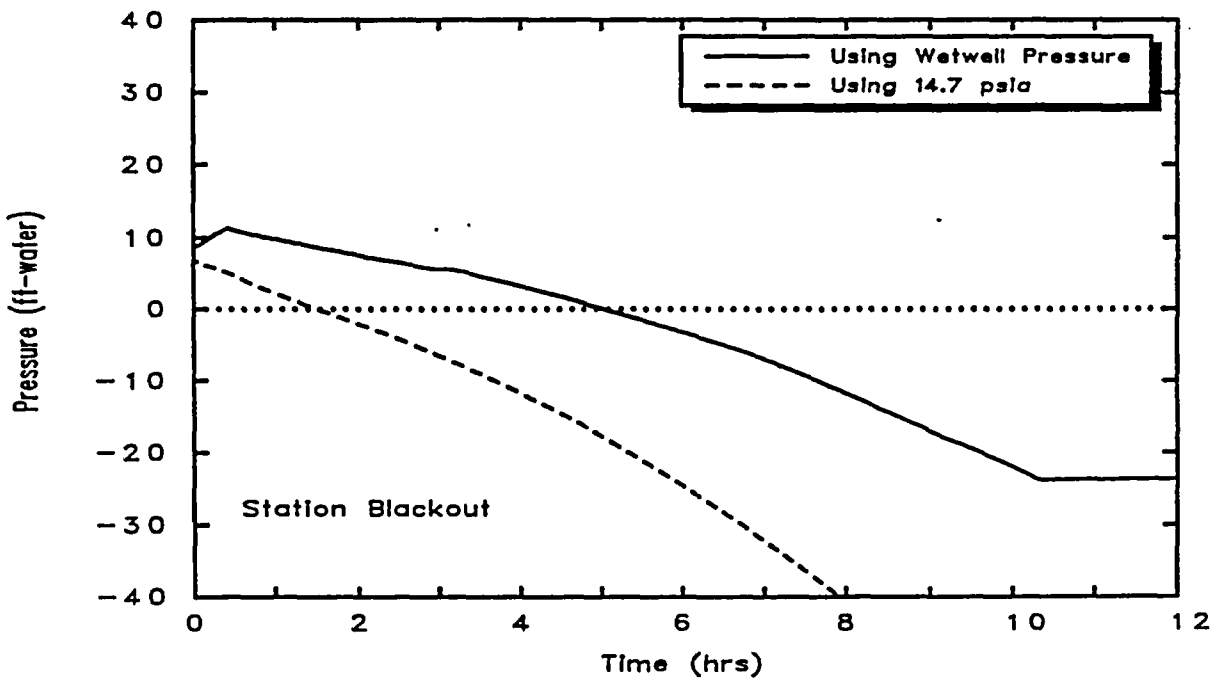


Figure 5-24: LPCS NPSH Margin

These calculations predict that the RHR and the LPCS pumps would not have sufficient NPSH to start at 12 hours if power were restored in the SB sequence or service water were restored in the PCS sequence. The times when the NPSH margins were predicted to go to zero are given in Table 5-11 for both sequences when computed using either the actual containment pressure or atmospheric pressure. This implies that these systems must start sooner than at 12 hours in order to prevent core damage. It is likely that if this information were integrated into the plant IPE that the predicted risk would increase.

Table 5-11: Time When NPSH Margin Lost for SB and PCS Transients

Transient Sequence	Using Wetwell Pressure		Using 14.7 psia	
	RHR	CS	RHR	CS
Station Blackout	9.7	5.0	5.4	1.5
Loss of Power Conversion System	7.2	3.0	3.9	0.6

5.4 Approach to Predicting Overpressure

Regulatory guidance for determining the minimum containment pressure at the time that pool temperature peaks has not been established. Several utilities, at least, have used calculations with simplifying assumptions that cannot be justified. The analyses discussed in Section 5.3.3 clearly illustrated that lower pressures are predicted by calculation where pressure reducing systems and processes are included in the calculational model. Further, the pressure strongly depends upon the suppression pool temperature.

Another way of looking at the pressure dependency on pool temperature is to plot the pressure versus the pool temperature. As an example, the wetwell pressure for the base case maximum pool temperature calculation (Case 1), is plotted as a function of the suppression pool temperature, in Figure 5-25. This curve starts at the left side of the plot and proceeds to the upper right corner where it turns around and comes back again. This behavior corresponds to suppression pool temperature in Figure 5-9 where the temperature first increases over time and then decreases again.

Four calculations are plotted in Figure 5-26 to illustrate the differences encountered in these calculations. Maximum pool temperature calculations for Cases 1 and 4 are compared to show potential pressure differences between a calculation with containment cooling models and a calculation without these models. The maximum cooling calculation and the station blackout calculations are also shown. The maximum cooling calculation is at the left side and the SB at the right. The initial vertical portions of these curves correspond to the conditions immediately following the LOCA where the sprays are actively suppressing the pressure.

All of the calculations run in this study are plotted together in Figure 5-27 to more fully illustrate how the pressure can vary at a given temperature depending on the modeling assumptions and the sequences selected. The transient sequences tend to remain lower than the LOCA sequences; and this was due to the lag between the suppression pool saturation pressure and the wetwell vapor pressure.

This process illustrates how the results from a spectrum of applicable sequences can be used to define a conservative lower pressure boundary. If we overlay the overpressure credits onto the figure, we visually see the validity of these credits. DAEC stated that an overpressure of 1.3 psi was needed for the LPCS. As shown in Figure 5-27, this 1.3 psi at a pool temperature of 201°F is clearly well below the lower pressure boundary, and therefore appears valid. The needed overpressure credits calculated by SEA (5.6 and 8.3 psi for the RHR with both pumps running at rated flow and the LPCS at rated flow, respectively) are also shown. The RHR is below the lower pressure boundary but the LPCS is borderline.

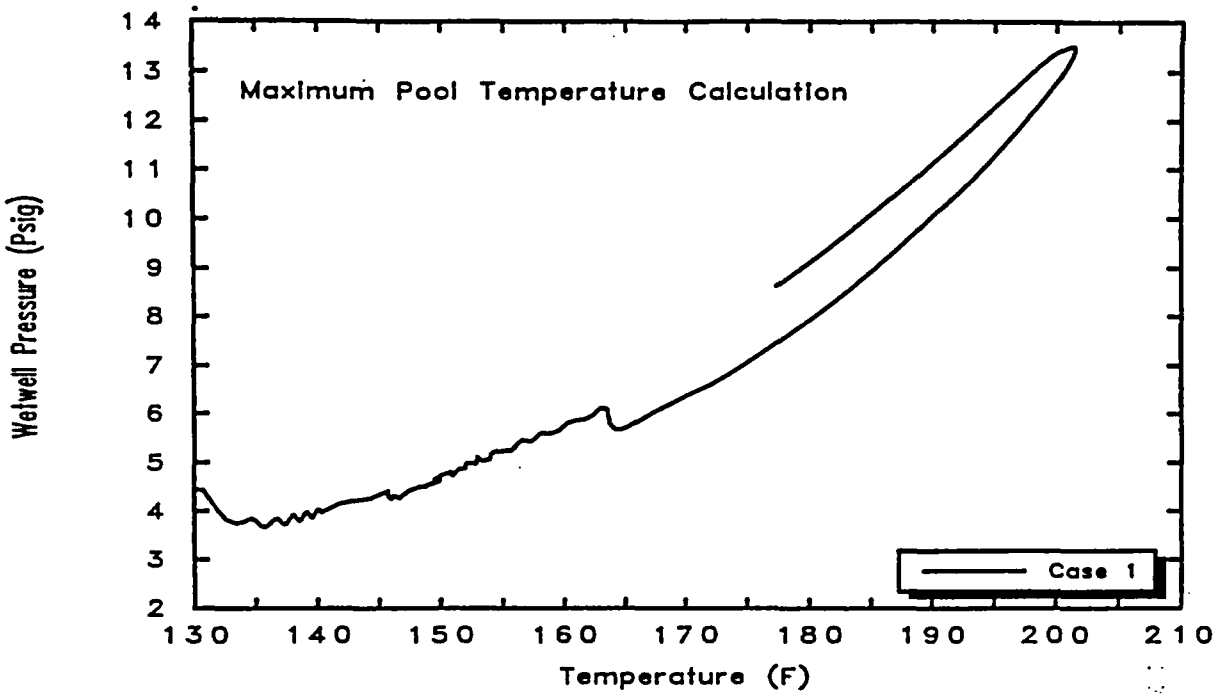


Figure 5–25: Pressure–Temperature Dependency (1)

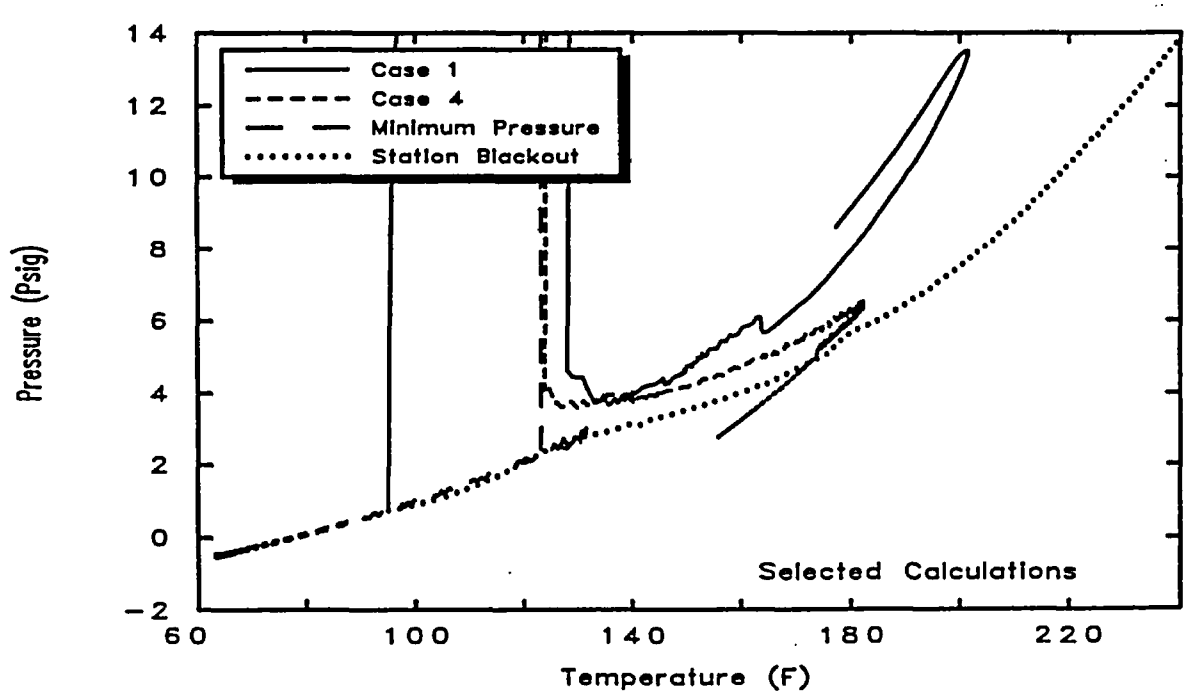


Figure 5–26: Pressure–Temperature Dependency (2)

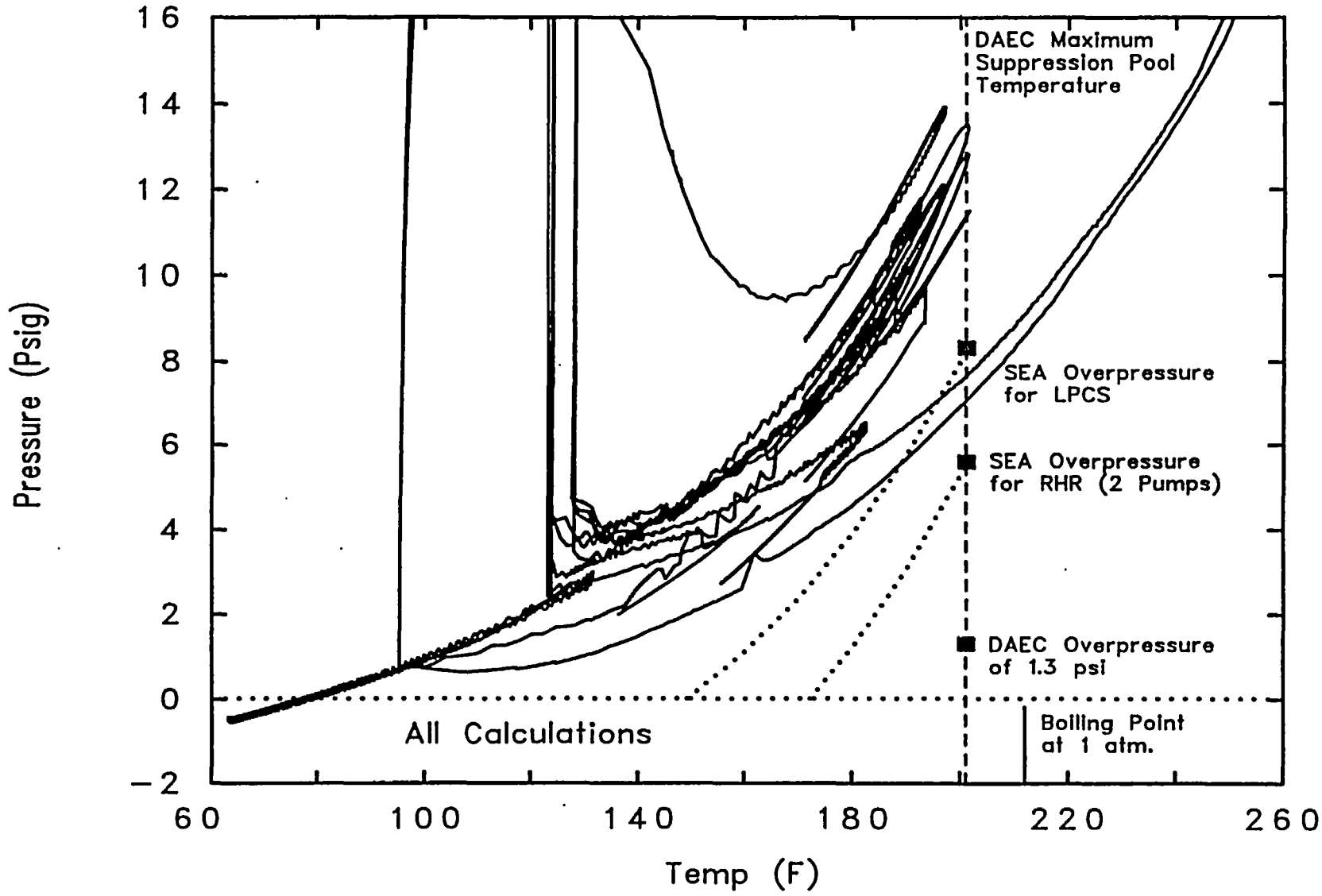


Figure 5-27: Pressure-Temperature Dependency (3)

The analysis presented in Section 5 shows:

- **Integrated time-dependent calculations that model all installed pressure-reducing systems and processes and cover the applicable range of accident sequences are needed to ensure that a conservative minimum pressure is determined for the purpose of granting an overpressure credit.**

- **These calculations show that oversimplified calculations do not predict conservative containment pressure for NPSH analyses.**

- A procedure for determining the minimum temperature-dependent pressure has been illustrated.

6.0 OVERALL REVIEW OF GL 97-04 SUBMITTALS

SEA reviewed the comments received in response to Generic Letter 97-04, looking for utility reliance on overpressure for an adequate NPSH margin, and for general trends and insights into compliance to regulatory guidance, and methodology. GL 97-04 requested information from all holders of operating licenses for nuclear power plants, except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor vessel. The purpose of GL 97-04 was to request information necessary to confirm the adequacy of NPSH available for ECC and containment heat removal.

6.1 General Comments Regarding GL 97-04 Submittals

GL 97-04 requested information in five specific different areas. The data collected by SEA during our review of these submittals was organized according to the five areas and is shown in Table 6-1. The following discusses the type of information received for each review area.

1. Specify the general methodology used to calculate the head loss associated with the ECCS suction strainers.

Most of the licensees responded by citing the regulatory basis for estimating the head loss (e.g., RG 1.82, Rev.0 or Rev. 1) and explaining how and if they took into consideration the effect of insulation debris and air ingestion. Although all the BWR plants are in the process of strainer replacement in response to NRC Bulletin 96-03, a majority of the responses provided plant licensing bases and head loss methodologies that existed before NRC Bulletin 96-03.

2. Identify the required NPSH and the available NPSH.

All the plants (with the exception of Millstone Nuclear Power Station Unit 2) identified both the available and required NPSH for each ECCS pump, for at least the low-pressure injection and recirculation pumps. The Millstone 2 plant stated that the ratio of available to required NPSH was greater than 1.01.

Most of the plants also provided data for:

- flow rates used to estimate frictional losses
- sump (or suppression pool) water temperature
- sump (or suppression pool) water level
- containment pressure

Some PWR plants used the vapor pressure of the pumped-fluid for the containment pressure but did not identify sump water temperature.

3. Specify whether the current design-basis NPSH analysis differs from the most recent analysis reviewed and approved by the NRC for which a safety evaluation was issued.

The submittals declared that their current design basis does not differ from the most recently reviewed and approved analysis. Most of the submittals still use the original NRC approved licensing basis, documented in their FSAR, as their current design-basis. Analyses changed from their original analyses were revised in response to identified deficiencies in the previous analyses or due to a reconfiguration of some of the systems.

4. Specify whether containment overpressure (i.e., containment pressure above the vapor pressure of the sump or suppression pool fluid) was credited in the calculation of available NPSH. Specify the amount of overpressure needed and the minimum overpressure available.

Most of the PWR plants responded that no overpressure was credited in their NPSH available analyses. However, a selected number of PWR plants and several BWR plants took a credit for overpressure in excess of atmospheric pressure.

Table 6-1: Summary of GL 97-04 Submittals

Plant Info		Strainer DH Basis (Q #1)	Required, and Available NPSH and Bases (Q#2)					Q#3	Credit for Containment Pressure (Q#4 and 5)			
Plant Name	RG 1.82, Rev.0,1,2	GL 85-22 (Vortex)	Strainer DH (ft H2O)	NPSH Margin (ft.)	Flowrate (gpm)	Pool Height (ft)	Pool Temperature	Current Design Basis Approved (Y/N)	Over Pressure Credit	Over Pressure Required (CS Pump) psi	Over Pressure Required (RHR Pump) psi	Over Pressure Available psi
PWR LARGE DRY												
Alvin W. Vogtle Nuclear Plant Unit 1&2	Rev. 1 (debris included)	Yes		CS = 18.7; RHR = 2.6; SI = 32.6;	CS = 2600; RHR = 4500			No	None			
Arkansas Nuclear One-Unit 1	Rev. 1	Yes	0.305	LPI P34a = 1.51; LPI P34b = 0.96; RBS P35a = 4.84; RBS P35b = 2.07	LPI = 4050; RBS = 1310			No (SAR will be updated)	None			
Arkansas Nuclear One-Unit 2	Rev. 1	Yes	0.16	CS 2P35a = 2.95; CS 2P35b = 3.24; HPSI 2P89c = .62	2P235a/b = 3200; 2P89c = 825			No (SAR will be updated)	None			
Braidwood Nuclear Power Station Unit 1&2	Rev. 0	No		CV = 14; SI = 12; RH = 6.1; CS = 4.3	No Info.			Yes	None			
Byron Nuclear Power Station Unit 1	Rev. 0	No		CV = 14; SI = 12; RH = 6.1; CS = 4.3	No Info.			Yes	None			
Callaway Plant	Rev.0	No	Loss coef: 0.30	RHR = 0.9; CS = 7.7; SI = 28.9; CC = 15.2	RHR = 4800; CS = 3950; SI = 691; CC = 567	FSAR		Yes	None			
Calvert Cliffs Nuclear Power Plant	Rev. 0	No	Loss Coef: 0.78	HPSI = 3; LPSI = 10.5; CS = 5.8	HPSI = 607; LPSI = 3000; CS = 1842	FSAR		No	None			
Comanche Peak Steam Electric Station	Rev. 1	Yes		RHR = 5; SI = 87.8; CC= 47.5	RHR = 4900; SI = 403; CC = 409			Yes	None			
Crystal River Unit 3	Rev. 0	No	< 1	BSP 1a = 2.0; BSP 1a = 1.3; DHP 1a = 1.5; DHP 1b =1.4		FSAR	212	No	None			
Davis-Besse Nuclear Power Station	Rev. 0	No	0.05	LPI Train 1 = 2.4; Train 2 = 2.7; CS Train 1 = 4.8; Train 2 = 3.9; HPI Train 1&2 = >>28-28	LPI = 4000; CS = 1500			Yes	None			
Diablo Canyon Nuclear Power Plant	Rev. 1 (RMI + Paint)	Yes		RHR cold leg = 4.8; RHR hot leg = 3.6; SI cold leg = 60; CC coldleg= 35	RHR cold = 4542; RHR hot = 4900; CS = 567; CC = 451			No	None			
Fort Calhoun Station Unit 1	Rev. 0 (50%)	No		CS = 1.1; HPSI = 13.11	CS = 3100; HPSI = 450			No	Credited	3.86 psig	3.86 psig	15.47 psig

Table 6-1: Summary of GL 97-04 Submittals

Plant Info		Strainer DH Basis (Q #1)	Required, and Available NPSH and Bases (Q#2)					Q#3	Credit for Containment Pressure (Q#4 and 5)			
Plant Name	RG 1.82, Rev.0,1,2	GL 85-22 (Vortex)	Strainer DH (ft H2O)	NPSH Margin (ft.)	Flowrate (gpm)	Pool Height (ft)	Pool Temperature	Current Design Basis Approved (Y/N)	Over Pressure Credit	Over Pressure Required (CS Pump) psi	Over Pressure Required (RHR Pump) psi	Over Pressure Available psi
H. B. Robinson Steam Electric Plant	Rev. 0 (80%)	No	0.12	RHR = 4.2	No Info			No	None			
Indian Point Station Unit 2	Rev. 0 (50%)	No	0.11	RHR = 13.9; Recirc. = 0.97; SI = 222	RHR = 3000; Recirc. = 3057; SI = 600			Yes	None			
Indian Point Station Unit 3	Rev. 0 (50%)	No	0.05	RHR = 3.3; SI = 39	RHRc = 4500; SI = 650			Yes	None			
Joseph M. Farley Nuclear Plant Unit 1	Rev. 0 (63%)	No	0.14	RHR = 3.78; CC = 68; CS = 1.3	RHR = 4415; CC = 1340; CS = 3050				None			
Kewaunee Nuclear Power Plant	Rev. 0	No	< 1.0	RHR = 17; No Calc. for SI & ICS pumps	RHR = 2600			No	None			
Oconee Nuclear Station Unit 1, 2 and 3	Rev. 0 (50%)	No	0.03	BS = 1.5; LPI = 7.2	No Info.		230 oF	No	Credited	2.28	0	2.9
Palisades Plant	Rev. o (10%)	No		For certain single failures, NPSH margin falls below 0. The plant has manufactures data supporting operation for several hours	CS = 2123 GPM; HPSI = 727 GPM			No	None	Over pressure required but not credited		
Palo Verde Nuclear Station Unit 1	Rev. 1	Yes		CS = 3.8; LPSI = 6.1; HPSI = 3.8	Runout flow			Yes	None			
Point Beach Nuclear Plant	Rev. 0	No		RHR = 10.2	No Info	7-inches	Saturated	No	None			
Prairie Island Nuclear Generating Plant	Rev. 0 (low vel.)	Yes (expts)	0	RHR @ runout = 13; RHR @ design = 19;	runout flow = 2600; design flow = 2000				None			
Robert Emmet Ginna Nuclear Power Plant	Rev. 1	Yes	0.95	RHRa = 5.6; SI = 141; CS = 46.5	RHR = 1500	Tech Specs	212 oF	Yes	None			
Salem Nuclear Generating Station Unit 1	Rev. 0 (50%) (debris less conservative)	Yes (ARL)		Cold Leg Recir. = 1.1; Hot Leg Recirc. = 4.1; Recirc. Spray Mode = 6.5	No Info			No	None			
Salem Nuclear Generating Station Unit 2	Rev. 0 (50%)	Yes (ARL)		Cold Leg Recir. = 3.9; Hot Leg Recirc. = 4.1; Recirc. Spray Mode = 6.5	No Info			No	None			

Table 6-1: Summary of GL 97-04 Submittals

Plant Info		Strainer DH Basis (Q #1)	Required, and Available NPSH and Bases (Q#2)					Q#3	Credit for Containment Pressure (Q#4 and 5)			
Plant Name	RG 1.82, Rev.0,1,2	GL 85-22 (Vortex)	Strainer DH (ft H2O)	NPSH Margin (ft.)	Flowrate (gpm)	Pool Height (ft)	Pool Temperature	Current Design Basis Approved (Y/N)	Over Pressure Credit	Over Pressure Required (CS Pump) psi	Over Pressure Required (RHR Pump) psi	Over Pressure Available psi
San Onofre Nuclear Station Unit 2	Rev. 1 (50% more conservative)	Yes		HPSI = 1.9; LPSI = 2.3; CS = 11.5	HPSI = 1000; LPSI = 5500; CS = 2500			No	None			
Seabrook Nuclear Station Unit 1	Rev. 1	Yes		CS = 0.54; RHR = 2.5; Charging = 12; SI = 24.5	No Info.			Yes	None			
South Texas Project Unit 1&2	Rev. 1	Yes		LHSI = 3.5; HHSI = 3.9; CS = 3.6	No Info.			No	None			
St. Lucie Unit 1	Rev. 0 (50%)	Yes (EBASCO Testing)	3	CS: 12.47; LPSI: 7.49; HPSI: 2.1	CS: 4165; LPSI 3500; HPSI: 640	23.49 ft-level Tech Specs	Saturared	No				
St. Lucie Unit 2	Rev. 0 (50%)	Yes (EBASCO Testing)	<1	CS: 5.43; HPSI: 1.07	CS: 3600; HPSI: 685	21.42 ft-level Tech Specs	Saturared	No				
Turkey Point Unit 3&4	Rev. 0	No		RHR short-term = 8.2; RHR long-term = 12.4	No Info.	2.93 ft	Saturated		None			
Waterford 3 SES	Rev. 1	Yes	< 1.6	HPSI = 7.35; CS = 13.27	HPSI = 890; CS = 2250	64% RWST Capacity		No	None			
Wolf Creek Generating Station	Rev. 0 (50%)	Yes (tested)		RHR = 0.9; CS = 6.7; SI = 19; CC = 16	RHR = 4800; CS = 3950; SI = 660; CC = 550				None			
Zion Nuclear Power Station Unit 1&2	Rev. 0	No		RHR = 1.44	Required SI NPSH of 24-25' @ 650gpm			No	None			

Table 6-1: Summary of GL 97-04 Submittals

Plant Info		Strainer DH Basis (Q #1)	Required, and Available NPSH and Bases (Q#2)					Q#3	Credit for Containment Pressure (Q#4 and 5)			
Plant Name	RG 1.82, Rev.0,1,2	GL 85-22 (Vortex)	Strainer DH (ft H2O)	NPSH Margin (ft.)	Flowrate (gpm)	Pool Height (ft)	Pool Temperature	Current Design Basis Approved (Y/N)	Over Pressure Credit	Over Pressure Required (CS Pump) psi	Over Pressure Required (RHR Pump) psi	Over Pressure Available psi
PWR SUB-ATMOSPHERIC												
Beaver Valley Power Station Unit 1	Rev. 0	No		RSP: 3, 2.3; LHSI: 0.6	RSP = 3400; LHSI = 4500	RSP = 1.75; LHSI=2.79	11 psia; 180 F	Yes (LOTIC)	Credited		3.25 psi short term; >2 psi long term	
Beaver Valley Power Station Unit 2				RSP: 0.9; LHSI: N/A	RAP: 3480	LOTIC	Saturated	Yes (LOTIC)	None			
Millstone Nuclear Power Station Unit 2	Rev. 1	Yes	0.43	No info other than NPSHA/NPSHR > 1.01	Run out flow	Top of sump	No credit for sub cooling	No	None			
Millstone Nuclear Power Station Unit 3	Rev. 1	Yes	Transient Head Loss	Recirc. = 15.1; CC = 100; SI = 113.3	No Info.	Tech Specs		No	None			
North Anna Power Station Unit 1	Rev. 1	Yes		HHSI = 41.1; LHSI = 0.7; Outside Recirc. = 1.79; Inside Recirc. Spray = 1.13	Design Flow			No	Credited	LOTIC Calucaltions		Margin: IRS (660 s) = .48; ORS (700 s) = .74; LHSI (3160 s) = .29
Surry Power Station Units 1 & 2	Rev. 1	Yes		LHSI (Recir. Mode) = 1.07; Outside Recir. = 0.83; Inside Recir. = 2.73	No Info.				Credited	No Info.	No. Info	Margin: IRS (700 s) = 1.1; PRS (700 s) = .35; LHSI (3160 s) = .29

Table 6-1: Summary of GL 97-04 Submittals

Plant Info		Strainer DH Basis (Q #1)	Required, and Available NPSH and Bases (Q#2)					Q#3	Credit for Containment Pressure (Q#4 and 5)			
Plant Name	RG 1.82, Rev.0,1,2	GL 85-22 (Vortex)	Strainer DH (ft H2O)	NPSH Margin (ft.)	Flowrate (gpm)	Pool Height (ft)	Pool Temperature	Current Design Basis Approved (Y/N)	Over Pressure Credit	Over Pressure Required (CS Pump) psi	Over Pressure Required (RHR Pump) psi	Over Pressure Available psi
PWR ICE CONDENSER												
Catawba Nuclear Station Unit 1 and 2	Rev. 0	Yes (ARL Tests)		CS a,b Injection = 71, 74; CS a,b Recirc. = 11, 13; SI a,b Injection = 47, 48; RHR a,b Injection = 76.25, 73.25; RHR a,b Recirc. = 5.25, 7.25; CC a,b Injection = 55.5, 55.5;	Maximum Calculated Runout Flow	Tech Specs	170 F	Yes	None			
D. C. Cook Nuclear Plants Units 1 and 2	Rev. 0 (50%)	Yes	< 1	RHR: 9; CTS: 22	Runout Flow 15600 GPM	Tech Specs (602-Level)	190 F	No	None			
Sequoyah Nuclear Plant	Rev. 1 (80%)	Yes		RHR = 9.26; CS = 11.93	CS = 5700		190 F	No	None			
Watts Bar Nuclear Plant	Rev. 1 (90%)	Yes		RHR = 1.7; CS = 3.7	No Info.	Top of Sump Level	190 F	No	None			
William B. McGuire Nuclear Station Unit 1 and 2	Rev. 0	Yes (ARL Tests)		CS a,b Injection = 45.9, 41; CS a,b Recirc. = 8.1, 1.7; SI a,b Injection = 25, 25.2; SI a,b Recirc. = 163.4, 165.7; RHR a,b Injection = 43.5, 43.7; RHR a,b Recirc. = 15.9, 15.4; CC a,b Injection = 21.1, 21.1; CC a,b Recirc. = 160.5, 160.5	All at Maximum Calculated Runout Flow; RHR = 4000 GPM	6 ft	190 F	Yes	None	Containment pressure = atm. pressure		

Table 6-1: Summary of GL 97-04 Submittals

Plant Info		Strainer DH Basis (Q #1)	Required, and Available NPSH and Bases (Q#2)					Q#3	Credit for Containment Pressure (Q#4 and 5)			
Plant Name	RG 1.82, Rev.0,1,2	GL 85-22 (Vortex)	Strainer DH (ft H2O)	NPSH Margin (ft.)	Flowrate (gpm)	Pool Height (ft)	Pool Temperature	Current Design Basis Approved (Y/N)	Over Pressure Credit	Over Pressure Required (CS Pump) psi	Over Pressure Required (RHR Pump) psi	Over Pressure Available psi
BWR MARK I												
Browns Ferry Nuclear Plant	Rev. 2	N/A		RHR Initial = 2.05, 10 min. = 0.39 w/ 2psig O.P., Long Term = 10.51; CS Initial = 8.77, 10 min. = 7.1, Long Term = 4.18	RHR: Initial: 11000; long term: 6500 gpm; LPCS Initial 3125; long term: 3125	FSAR Tech Spec	Initial 95; 10 min 150 F; Long term: 177 F	No	Credited	2	2	No Info
Brunswick Steam Electric Plant Unit 1&2	Rev. 2 (96-03)	N/A		600 s after LOCA = 1.2	Runout flow	FSAR/Tech Spec		No	None			
Cooper Nuclear Station	Rev. 2	N/A		CS = 15.93; RHR a,b,c,d = 9.28	CS = 4720; RHR = 7700	FSAR/Tech Spec	175.4; 195.9	No	Credited	0 @ 95 F; 0 @152.3 F; 0 @175.4 F; .01 @ 190.7 F; .11 @ 195.9 F	0 @ 95 F; 0 @152.3 F; .14 @ 175.4 F; 2.79 @ 190.7 F; 3.89 @ 195.9 F	0 @ 95 F; 6.34 @ 152.3 F; 4.80 @ 175.4 F; 6.99 @ 190.7 F; 7.77 @ 195.9 F
Dresden Nuclear Power Station Unit 2&3	Rev. 0 (25%)	No		LPCI Short Term = 10.4; Long Term = 1.0; LPCS Short Term = 7.0; Long Term = 5.6	No Info.	FSAR	FSAR	Yes	Credited	Short Term: 6.5 Long Term: 0.2	5.1/2.1	11.7/2.9
Duane Arnold Nuclear Power Plant	Rev. o (50%)	No	CS: 1.6; RHR:0.53	Run-out flow: Max. Torus Cooling : 6 @ 75 F; 2.2 @ 95 F; Min. Torus Cooling: 6.8 @ 75 F; 5.1 @ 95 F; Rated flow: Max Torus Cooling: 15.1 @ 75 F; 12.9 @ 95 F; Min Torus Cooling: 14 @ 75; 11.9 @ 95	Max. Torus Cooling: 5400 gpm; Min. torus Cooling: 4000 gpm		201 for Initial Sump Temp of 95 oF	No	Credited	0 @ run-out flow; 1.3 a rated flow	0 @ both run-out and rated flow	6.3 psig
Enrico Fermi Atomic Power Plant	Rev. 0 (50%)	No		CS = 3.04; RHR Containment cool. mode = 4.2; RHR Sup. Pool cool. mode = 4.2	No Info.	Tech Specs			None			
James A. FitzPatric Nuclear Power Plant	Rev. 0 (50%)	No	< 1.0	RHR =14.5 @ no OP credit; -4.6 @ 2 psi OP credit; CS = 20.9 @ no OP credit; -4.0 @ 1.7 psi OP credit	RHR = 10,500 @ no OP Credit; 7700 @ 2.0 psi OP credit; CS = 6000 @ no OP credit; 4725 @ 1.7 OP credit		213 oF	No	Credited	1.7 psig	2.0 psig	4 psig

Table 6-1: Summary of GL 97-04 Submittals

Plant Info		Strainer DH Basis (Q #1)	Required, and Available NPSH and Bases (Q#2)					Q#3	Credit for Containment Pressure (Q#4 and 5)			
Plant Name	RG 1.82, Rev.0,1,2	GL 85-22 (Vortex)	Strainer DH (ft H2O)	NPSH Margin (ft.)	Flowrate (gpm)	Pool Height (ft)	Pool Temperature	Current Design Basis Approved (Y/N)	Over Pressure Credit	Over Pressure Required (CS Pump) psi	Over Pressure Required (RHR Pump) psi	Over Pressure Available psi
Edwin I.Hatch Nuclear Plant Unit 1	Rev. 0 (75%)	No		RHRa ST = 3.47 LT = 6.67; RHRb ST = 3.99 LT = 6.77; RHRc ST = 3.28 LT = 8.4; RHRd ST = 4.21 LT = 7.36; CSa ST = 11.77 LT = 10.28; CSb ST = 7.73 LT = 6.52	RHR ST = 10,600 LT = 7700; CS ST = 5900 LT = 4725		200 oF	No	Credited	2.35 for LT (long term)	2.35 fot LT	5 psi is the minimum margin between calculated containment pressure and the over pressure credited for NPSHa
Edwin I.Hatch Nuclear Plant Unit 2	Rev. 0 (75%)	No		RHRa ST = 21.7 LT = 8.23; RHRb ST = 21.7 LT = 8.23; RHRc ST = 21.62 LT = 8.18; RHRd ST = 21.62 LT = 8.18; CSa ST = 24.02 LT = 7.28; CSb ST = 24.03 LT = 7.28	RHR ST = 10,600 LT = 7700; CS ST = 5900 LT = 5060		200 oF	Yes	Credited	May request for containment over pressure in future		
Millstone Nuclear Power Station Unit 1	Rev. 1	Yes		LPCI = 8; CS = 10	No Info.	Top of sump	203 oF	No	Credited	9 psig	9 psig	9-10 psig
Monticello Nuclear Generating Station	Rev. 0 (0%)	No		LPCS = 1.7; RHR = 2.1	No Info.	Tech Specs		Yes	Credited	6.1 (4-15 hrs.)	6.1	6.21
Nine Mile Point Nuclear Station Unit1	Rev. 0 (50%)	No	8.4	LPCore Spray = -4.65; CS primary = 0.2; CS secondary = 1.9	LPCS =4825; CS primary = 3820; CS secondary = 3720	18.5 ft	163 oF	Yes	Yes/No		Over pressure not credited, but required	
Oyster Creek Nuclear Power Station	Rev. 0	No		Limiting Case LPCS = 0.036	LPCS = 5000 GPM			Yes	None	96-03 response will request overpressure		

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Plant Name	RG 1.82, Rev.0,1,2	GL 85-22 (Vortex)	Strainer DH (ft H2O)	NPSH Margin (ft.)	Flowrate (gpm)	Pool Height (ft)	Pool Temperature	Current Design Basis Approved (Y/N)	Over Pressure Credit	Over Pressure Required (CS Pump) psi	Over Pressure Required (RHR Pump) psi	Over Pressure Available psi
Peach Bottom Atomic Power Station Unit 2&3	Rev. 0 (50%)	No		RHR = 4.03	Run out flow			No	Credited	states that data is in graphs although no graphs were found	states that data is in graphs although no graphs were found	
Quad Cities Nuclear Power Station Unit 1&2	Rev. 0 (25%)	No		RHR Short Term = 7.8; Long Term = 2.6; CS Short Term = 5.2; Long Term = 9.8; HPCI = 4.7	No info.			No	Credited	Short Term: 7.3; Long Term: -0.7	6.2/3.2	9.5/3.4
Vermont Yankee Nuclear Power Station	Rev. 1 (debris included)	Yes		CS short-term = 0.3; RHR short-term = 3.6; CS long-term = 0.9; RHR long-term = 1.4	short term = 7100; long-term = 7000	12 ft	176 oF	No	None			

Table 6-1: Summary of GL 97-04 Submittals

Plant Info		Strainer DH Basis (Q #1)	Required, and Available NPSH and Bases (Q#2)					Q#3	Credit for Containment Pressure (Q#4 and 5)			
Plant Name	RG 1.82, Rev.0,1,2	GL 85-22 (Vortex)	Strainer DH (ft H2O)	NPSH Margin (ft.)	Flowrate (gpm)	Pool Height (ft)	Pool Temperature	Current Design Basis Approved (Y/N)	Over Pressure Credit	Over Pressure Required (CS Pump) psi	Over Pressure Required (RHR Pump) psi	Over Pressure Available psi
BWR MARK II												
LaSalle County Nuclear Power Station Unit 1&2	Rev. 0 (25%) GL 96 03	N/A	4.1 (Clean)	RHR = 1.3; LPCS = 13.5; HPCS = 10.9	No Info.			No	None			
Limeric Generating Station Unit 1&2	Rev. 0 (50%)	No		RHR = 2; CS = 2	Runout flow		185 oF	No	None			
Susquehanna Steam Electric Station Unit 1&2	Rev. 0 (50%) (debris less conservative)	Yes (RMI)		LPCS runout = 0.57; HPCI = 10.4; RHR runout = 9.74	No Info.				None			
WPPSS Nuclear Project unit 2	Rev. 0 (50%)	No	3.62	Present Design: RHR 25.9; LPCS = 26.90; HPCS = 15.9; 96-03: RHR = 18.21; LPCS = 18.86; HPCS = 8.36	RHR = 7900; LPCS = 7800; HPCS = 7175	30 ft	204 oF	No	None			

Table 6-1: Summary of GL 97-04 Submittals

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Plant Name	RG 1.82, Rev.0,1,2	GL 85-22 (Vortex)	Strainer DH (ft H2O)	NPSH Margin (ft.)	Flowrate (gpm)	Pool Height (ft)	Pool Temperature	Current Design Basis Approved (Y/N)	Over Pressure Credit	Over Pressure Required (CS Pump) psi	Over Pressure Required (RHR Pump) psi	Over Pressure Available psi
BWR MARK III												
Clinton Power Station	Rev. 0	No	< 1.0	Not Much Info: min. available NPSH for ECCS Pumps should be over 9.7	No Info.	FSAR	212	No	None			
Grand Gulf Nuclear Station Unit 1	Rev. 0	No	< 1	RHRa = 4; RHRb = 3.5; RHRc = 3.7; LPCS = 4.4; HPCS = 5	Runout Flow of 9100 gpm		212 oF	Yes	None			
Perry Nuclear Power Plant	Rev. 2	Yes		RHRa,b,c = 22.5; LPCS = 23.4; HPCS = 21.6	Runout flow				None			
River Bend Station Unit 1	Rev. 2	Yes		LPCS = 14.72; HPCS = 12.21; RHRa = 14.17; RHRb = 14.2; RHRc = 14.86	Runout flow; RHR = 6000; LPCS = 6400	10.75 ft	185 oF	No	None			

Nomenclature Used in Table 6-1

BS	Building Spray
BSP	Building Spray Pumps
CS	Containment Spray
CV / CC	Centrifugal Charging
DHP	Decay Heat Pumps
ECCS	Emergency Core Cooling System
FSAR	Final Safety Analysis Report
HHSI	High Head Safety Injection
HPCI	High Pressure Containment Injection
HPSI	High Pressure Safety Injection
ICS	Containment Spray
IRS	Inside Recirculation Spray
LHSI	Low Head Safety Injection
LOCA	Loss of Coolant Accident
LPCI	Low Pressure Containment Injection
LPCS	Low Pressure Containment Spray
LPSI	Low Pressure Safety Injection
LT	Long Term
NPSHa	Net Positive Suction Head Actual
NPSHr	Net Positive Suction Head Required
OP	Over Pressure
ORS	Outside Recirculation Spray
RHR	Residual Heat Removal
RSP	Recirculation Spray Pumps
RWST	Refueling Water Storage Tank
SI	Safety Injection
ST	Short Term

5. When containment overpressure is credited in the calculation of available NPSH, confirm that an appropriate containment pressure analysis was done to establish the minimum containment pressure.

In several cases, credit was taken for overpressure using containment pressure analyses that have not been reviewed and accepted by the NRC. Often licensees cited FSAR analyses as the basis for crediting overpressure. This is inconsistent with guidance provided in CSB 6-1 (SRP 6.2.1.5).

6.2 Insights Drawn from GL 97-04 Submittals

The following insights were drawn from this review:

Interpretation of Regulatory Guidance The submittals suggest that licensees have generally interpreted the guidance provided in RG 1.1, RG 1.82, and the SRP correctly. For example, most plants have calculated NPSH required assuming runout flow over short term and design flow (or alternately runout flow) over long term. Plants that took credit for lower ECCS flow during short term have explicitly stated that orifices were placed in the piping network to ensure that runout flow conditions would not result either during the short term or the long term. However, errors in interpreting the guidance were found. For example, the subatmospheric containments for Sequoyah and Watts Bar use the standard atmospheric pressure of 14.7 psia to be consistent with RG 1.1. However, the regulatory position stated in RG 1.1 is the containment pressure present prior to the postulated LOCA, i.e., less than atmospheric operating pressure. The utility should have either cited SRP 6.2.2 or used their operating containment pressure.

Accident Sequences Analyzed All NPSH analyses were based on the design basis accident loss-of-coolant accident (DBA LOCA). A few plants analyzed the SBLOCA in addition to the DBA LOCA. None of the analyses included non-LOCA sequences, e.g., transient sequences.

Strainer Blockage The design basis for most of the PWR plants is RG 1.82, Rev. 0 which requires that NPSH analyses consider partial loss of screen area. Surprisingly, the blockage fraction used in the analyses varied between 25% and 80% on a plant specific basis. Some plants have used higher blockage fractions to establish that strainers can handle a large quantity of unqualified paint chips and metallic insulation fragments.

Although BWR plants are into the strainer replacement process in response to NRC Bulletin 96-03, most of the BWR plants still indicate that their design basis is RG 1.82, Rev. 0. The exceptions are Browns Ferry, Cooper, Perry and River Bend, which explicitly stated that their design basis is updated to RG 1.82, Rev. 2. In response to issuance of RG 1.82, Rev. 1, several plants (17 PWR plants and three BWR plants) updated their NPSH analyses to reflect findings of NUREG-0897. Mostly, these Rev. 1 updates addressed the vortex issue that was resolved by either conducting small-scale experiments at the Alden Research Laboratory (ARL) or by conducting full scale tests at the plant.

Only a select number of PWR plants addressed the debris issue (e.g., Comanche Peak, Palo Verde, St. Lucie and Vogtle). In some cases (e.g., St Lucie) the debris analyses apparently revealed that RG 1.82, Rev. 0 presents the more limiting case.

Air Ingestion Because RG 1.82, Rev. 0 did not address the issue of air ingestion (or vortex suppression) and most plants still base their analyses on Rev. 0, most plants have not addressed this issue.

Sump or Suppression Pool Water Levels Several plants have explicitly stated that the sump (or torus) water levels used were consistent with Technical Specifications or FSAR values. To add conservatism (and mostly to separate out RWST level related issues from NPSH analyses), a few PWR plants assumed a water level at the top of the sump, thereby conservatively ignoring additional liquid column height on top of the sump (e.g., Millstone, Watts Bar and Waterford).

Staying Current SEA's review also suggests that licensees have significantly changed their NPSH calculation since their last NRC review. In some cases, changes have included taking credit for containment pressure without documented minimum pressure analyses that confirm the availability of such higher pressure.

Operating with Inadequate NPSH Margin Two plants (Nine Mile Point and Palisades) have negative NPSH margins for their limiting case but both licensees concluded that operation at negative NPSH margin for several hours would not degrade pump performance, as confirmed by manufacturer testing. Apparently NRC reviewed these analyses and approved them.

Reliance on Containment Overpressure Ten BWR plants (all Mark I designs) and five PWR plants (2 large dry and 3 subatmospheric designs) explicitly took credit for containment overpressure above the vapor pressure corresponding to the sump (or suppression pool) maximum temperature. In addition, one PWR and one BWR took credit for operating with a negative NPSH margin. Also, several other BWR plants indicated a probable future request for credit for overpressure as part of strainer replacement effort. This review indicates the likelihood that more plants will request containment overpressure credit to maintain a positive margin once insulation debris is included.

The PWR plants that took credit for containment overpressure are Beaver Valley Unit 1, Fort Calhoun Station Unit 1, Oconee Nuclear Station Unit 1, Surry Power Station Units 1 and 2, and North Anna Power Station Unit 1. The largest value for containment overpressure assumed by a PWR is 3.86 psig (Fort Calhoun).

Among BWR plants, Dresden, Quad Cities, Nine Mile Point and Monticello took credit for containment pressure in excess of 6 psi, reaching as high as 9 psi in the case of Nine Mile Point. Their confirmatory analysis does not appear to be consistent with guidance provided in CSB 6-1.

7.0 CONCLUSIONS AND RECOMMENDATIONS

The following conclusions and recommendations were drawn from this study.

Concern	Conclusion	Recommendation
Subsuming regulatory guidance.	Current guidance was found generally intractable, in need of clarification in several areas, and lacking a comprehensive roadmap to guide and analyst through the process. Regulatory guide deficiencies have likely contributed to documented inconsistencies found in utility NPSH analyses.	**SEA recommends that RG 1.1 be withdrawn and RG 1.82, Rev. 2 be revised (i.e., Revision 3) into a single comprehensive Regulatory Guide that clarifies existing guidance and functions as a roadmap to all related documents.** Such documents include applicable paragraphs in the Code of Federal Regulations, applicable sections in the SRP, applicable technical documents such as NUREGs, and other appropriate regulatory documents. Simultaneously, applicable sections of the SRP require updating to ensure complete guidance without conflicts.
Clarification of Regulatory Guidance		
Applicable systems.	Additional clarification is needed regarding which systems are included in the NPSH analyses. Applicable systems for the determination of the maximum pumped-fluid water temperature (minimum cooling) are not the same as applicable systems for the determination of minimum pressure (maximum cooling). For example, analyses have neglected non-safety rated systems such as BWR containment sprays and coolers in the calculation of containment pressure.	Regulatory guidance should clearly specify applicable systems for both minimum and maximum containment cooling. These systems include both active systems (e.g., containment sprays) and passive systems (e.g., heat transfer to structures).
Containment pressure for available NPSH determination.	Regulatory guidance contains conflicting information regarding the appropriate containment pressure for the calculation of available NPSH. RG 1.1 specifies the actual containment pressure present prior to LOCA while the SRP specifies both atmospheric pressure and the vapor pressure of the sump water. It is likely that utilities have been using standard atmospheric pressure of 14.7 psia and it is further likely that many utilities can not show a positive NPSH margin if they use the	The NRC should clarify the containment pressure that should be used in NPSH analyses. The NRC should determine which pressure has been used by the utilities and what would be the impact of specifying a containment pressure different than what has been historically used. For example, if a utility used standard atmospheric pressure but is now forced to use the sump water vapor pressure, could the utility still show a positive NPSH margin? If atmospheric pressure is to be used, does the analyst use 14.7 psia or

	sump water vapor pressures. Using the pumped-fluid vapor pressure is tantamount to specifying that the NPSH analysis must assume the standard atmosphere boiling temperature as the maximum pool temperature.	the actual plant atmospheric pressure?
Granting overpressure credit.	Some utilities already must use an overpressure credit to show positive NPSH margins and other are likely to require an overpressure credit as a result of including additional strainer head losses associated with LOCA generated debris. Regulatory guidance regarding the determination of minimum containment pressure is incomplete and actually not available for BWR plants. In fact, the existing PWR guidance was developed for a different purpose, i.e, the guidance addresses the direct dependency of core flooding rate (short term) on containment pressure, not on NPSH analysis (long term). **Existing analyses that justify an overpressure credit were likely based on oversimplified models resulting in non-conservative estimates for containment pressure.** **Integrated time-dependent calculations that model all installed pressure-reducing systems and processes and cover the applicable range of accident sequences are needed to ensure that a conservative minimum pressure is determined for the purpose of granting an overpressure credit.**	Regulatory guidance should be developed for both PWR and BWR plants that is specifically applicable to determining the potential for overpressure credit in NPSH analysis. Guidance should be comprehensive and its development should be based on NRC approved state-of-the-art system level computer analysis codes, such as CONTAIN and MELCOR. It should include easily overlooked aspects of calculating minimum containment, such as containment leakage, non-safety related systems capable of removing heat from the containment, and all passive heat transfer from the containment. The guidance should also address accident scenarios (e.g., transients) other than the design basis accident. Note that BWR transients differ from LOCA in that the effluence from the RCS passes through the suppression pool prior entering the atmosphere. Granting of overpressure credit should be done on a case by case basis.
Appropriate decay heat power for NPSH analysis.	Decay heat power can have a strong influence on predicting maximum pumped-fluid water temperatures and on predicting minimum containment pressures; however, regulatory guidance regarding the appropriate decay heat power to use in NPSH analysis is generally	Regulatory guidance should be clarified by including clear instructions regarding the appropriate decay heat power. This guidance should also specify the appropriate decay heat standard. Note that the ANS decay heat standard is known to generally overpredict the decay power level.

	missing from exiting guidance. In fact, the guidance available in SRP 6.2.1.5 for calculating PWR minimum containment pressure seems incorrect, i.e., the guidance states that the minimum pressure calculation should be based on the requirements of 10 CFR part 50, Appendix K. But these requirements artificially increased the power as a safety factor when the power should actually be decreased for conservatively predicting minimum pressure.	
Appropriate methods to predict NPSH.	Inconsistencies have been documented in utility NPSH analyses that involve both the calculational methodology and the application of the methodology. An inappropriate use of water densities was documented in GL 97-04, i.e., hot-fluid correction factor. Inconsistencies include the use of the appropriate flow rate for estimating frictional head losses, i.e., design, rated, runout, or some operator reduced flow rate. **It is likely that not all plants have considered surface fouling in the piping and heat exchangers.**	It is recommended that a sample comprehensive and approved PWR and BWR NPSH analysis be provided to the utilities that can be used as a template for other analyses to facilitate completeness, standardization, and NRC review.
Strainer head losses	A conservative estimate of strainer head losses due to both operational and LOCA generated debris is essential to ensuring adequate NPSH. Historically, strainer head losses were estimated analytically and usually assumed that 50% of the strainer holes were completely blocked. Note that blocking 50% of the holes does not produce the same head loss as partially blocking all the holes. Strainer head losses should be based on available experimentally measured head losses. **SEA review of selected plants has shown analytically estimated strainer head losses substantially less than those would be predicted based on recent experimental measurements.**	Clarification of regulatory guidance should include all recently developed guidance on LOCA debris generation, debris transport, and predicting strainer head loss.

PRA Evaluations		
CDF Dependency on potential loss of NPSH margin	**Generic results from a screening survey indicate that for both BWR plants and PWR plants, the unavailability of recirculation core cooling will increase the total CDF values by two orders of magnitude.** For BWR plants, only 7% of this increase is attributed to LOCA, with most of the remainder attributed to transients, whereas, for PWR plants, 91% is attributed to LOCAs. Thus, the potential loss of NPSH margin associated with non-LOCA accident sequences has significant potential impact on risk assessments.	It is recommended that the PRA aspects of NPSH analysis be studied more thoroughly than was possible in this study.
Bounding Conditions for Estimating Maximum Pool Temperatures and Minimum Containment Pressure	It is uncertain that bounding containment conditions determined by examining DBA-LOCAs also bound conditions that exist during non-LOCA accident sequences. BWR transient sequences with SRV/ADS flows entering the suppression pool at a submerged elevation have potentially more severe bounding conditions than a LOCA. In BWR transient sequences, where RHR cooling is lost but core makeup is still provided by HPCI until battery depletion, the containment conditions become much more extreme. The more extreme conditions could affect PRA results where credit was taken for use of HPCI cooling prior to battery depletion.	It is recommended that regulatory guidance be extended to address risk important non-LOCA accident sequences. Specifically, the question of whether or not LOCA sequences adequately bound containment conditions for NPSH analysis should be investigated more thoroughly than was possible in this study. The question of whether or not the loss of NPSH margin can significantly impact the timing of events in severe accidents, thus increasing the predicted risk, should also be addressed. The question of whether or not pumps can survive the high pool temperatures associated with transient sequences should also be examined.

Utility NPSH Analyses		
Staying current with plants modifications and plant aging.	Uncertainty exists as to whether or not NPSH analyses are updated as plants undergo modifications and as components such as heat exchangers and piping age. Over time the heat removal capability of these systems may degrade, (i.e., surface fouling) thereby increasing the maximum potential sump or suppression pool water temperature with a corresponding reduction in NPSH margin. As pipes age, their surface roughness can increase with a correspond increase in frictional pressure losses.	Recommend each utility maintain a living comprehensive calculational document reflecting current plant conditions.
Utility Responses to GL 97-04	All NPSH analyses were based on the design basis LOCA. Some plants have likely changed their NPSH analysis since their last approved NRC review. Most PWR plants have not updated their design basis from RG 1.82, Rev. 0 to incorporate effects of insulation debris. As a result, most plants have not addressed the air ingestion issue and strainer blockage is still based on blocking a fraction of the strainer area. These blockage fractions varied considerably, i.e., from 25% to 80%. A significantly number of BWR and PWR plants either took credit for containment pressure or have indicated that they require containment overpressure to maintain positive NPSH margin following a DBA LOCA. Two plants have negative NPSH margins for their limiting case but assume that the pumps can still be operated safely for several hours. Overpressure credits, at least in some cases, are not supported by documented analysis justifying ensuring available containment pressure.	SEA recommends that the NRC review plant NPSH analyses in much more detail than is possible with the information available in the GL 97-04 responses.

8.0 REFERENCES

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