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A Review of the South Texas Project Probabilistic Safety Analysis for Accident Frequency Estimates and Containment Binning

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ABSTRACT

The objective of this review is to evaluate the South Texas Project (STP) Probabilistic Safety Analysis (PSA) for the USNRC. The PSA was reviewed for thoroughness of analysis, accuracy in plant modeling, legitimacy of assumptions, and overall quality of the work. The review is limited to the internal event analysis and the fire sequence analysis.

This review is not a quantitative evaluation of the adequacy of the PSA. The adequacy of the PSA depends on the intended uses and must be addressed on a case-by-case basis by the licensee and the NRC. This review identifies strengths, weakness, and areas where additional clarification would assist the NRC in evaluating the PSA for specific regulatory purposes.

The licensee, Houston Lighting and Power (HL&P), reviewed a draft version of this report prior to its final release to the USNRC. The responses provided by HL&P are provided in detail in appendices to this report, and they are summarized in the main body of the report. All issues raised during the review were adequately addressed by HL&P in their responses.

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Acknowledgements

The authors wish to acknowledge the efforts of Houston Lighting and Power and Pickard Lowe and Garrick. We also appreciate the help and assistance of Erulappa Chelliah and George Dick of the NRC. Their cooperation on requests for information and response to questions greatly facilitated this review and enhanced its quality and utility to the NRC.

Executive Summary

This report summarizes a review of the South Texas Project (STP) Probabilistic Safety Assessment (PSA). The PSA was produced by Houston Lighting and Power Company (HL&P) using the services of Pickard, Lowe, and Garrick, Inc. (PLG) of Newport Beach, California.

The review was conducted by Sandia National Laboratories (SNL) with assistance from Science and Engineering Associates, Inc. (SEA). This report focuses on internal initiating events and the fire event analyses only.

The May 1989 version of the PSA was reviewed. Other material utilized in the review included: An up-to-date Final Safety Analysis Report (FSAR), System Descriptions as included in the PSA, numerous Piping and Instrumentation Diagrams (P&IDs), logic diagrams, elementary wiring diagrams, technical specifications, and emergency operating procedures (EOP). Three site visits by the reviewers supplemented this written material. A draft report was reviewed in detail by HLP who then provided written responses to issues raised in the draft report.

In general, the STP PSA is a state-of-the-art Level 1 risk assessment. The detail to which the plant was modeled and the engineering analyses justifying this model are good, although certain parts of the analyses were not sufficiently documented. The PLG methodology and its application to STP are not always clearly explained. Several major components of the methodology, such as the Human Reliability Analysis (HRA), the uncertainty analysis, and the split fraction definition and quantification, had to be explained and illustrated in detailed presentations by HLP and PLG personnel to the reviewers. A simple example of the methodology would aid in understanding the nuances of the techniques.

Despite the difficulties in understanding the documentation, the PSA analysis was well done. The STP PSA analysts exhibited a clear understanding of the PLG methods. Their application of these methods to STP was proper. The level of detail of the models was quite high and consistent with current state-of-the-art PRAs. Whenever concerns regarding PSA models, assumptions, data, or methods arose during the review, these concerns were explained satisfactorily to the review staff.

The Internal Events analysis shows a core damage frequency estimate of 1.7×10^{-4}/yr. This result is similar to PWR results from NUREG-1150. The core damage frequency is dominated by loss of electrical power sequences from both offsite and onsite events. Of the 21 dominant sequences reported, 15 involved loss of electrical power initiators. These sequences accounted for 80% of the core damage frequency accounted for in these 21 sequences. The models used by HLP for electrical power initiating events and for recovery of electrical power outages are conservative compared to those used in the NUREG-1150 analyses. However. the utility believes strongly that the data for the power grid and the STP plant support these results. No LOCA sequences involving failure of injection or recirculation cooling were found to be dominant. This appears to be due to the high level of independence between ECCS trains and the capability of ECCS pumps to operate in the recirculation mode without room cooling.

Interfacing LOCA sequences (V sequences) were found to be unimportant by the STP PSA. However, the rationale for screening this class of sequences from the set of dominant sequences was deemed questionable by the PSA reviewers. STP provided a highly detailed model and quantification of the V-sequence for STP in response to initial reviewer concerns. The STP V-sequence model provides a very sound, rigorous analysis. However, some minor issues regarding this model should be clarified before the V-sequence is accepted as non-dominant for STP. These issues are discussed in detail in this report and should not provide any serious obstacles to acceptance of the V-sequence analysis.

A number of general conclusions in regards to the documentation and methodology of the fire analysis are as follows:

a. The STP fire PSA as it is currently written as a stand-alone document is unreviewable. Substantial additional information as is provided in utility responses in Appendix 6 of this report would need to be included to allow for reproducibility of the results.

b. The South Texas Project has an area segregated three safety train design which substantially reduces the fire-induced core damage frequency contribution for fire zones outside of the control room.

c. The fire risk for the STP control room is an order of magnitude lower than what has typically been found in other fire PRAs. This difference is the result of lower severity factor probability assignments than have been used in other studies.

In view of the changes to the PSA done by HLP in response to issues raised by the review, there appears to be no special safety problems identified at STP. Furthermore, there do not appear to be any potentially significant risk contributors which may have been left out of or improperly screened out of the analysis.

1.0 INTRODUCTION

This report summarizes a review of the South Texas Project (STP) Probabilistic Safety Assessment (PSA). [1] The PSA was produced by Houston Lighting and Power Company (HLP) using the services of Pickard, Lowe, and Garrick, Inc. (PLG) of Newport Beach, California.

The review was conducted by Sandia National Laboratories (SNL) with assistance from Science and Engineering Associates, Inc. (SEA). This report focuses on internal initiating events only.

The May 1989 version of the PSA was reviewed. Other material utilized in the review included: An up-to-date Final Safety Analysis Report (FSAR), [2] System Descriptions as included in the PSA, numerous Piping and Instrumentation Diagrams (P&IDs), logic diagrams, elementary wiring diagrams, technical specifications, and emergency operating procedures (EOP). Three site visits by reviewers supplemented this written material. A draft report was reviewed in detail by HLP who then provided written responses to issues raised in the draft report. These responses are included in the appendices of this final report.

In Section 2 the assumptions regarding the plant systems which were incorporated into the PSA are discussed. This section serves as a review of how accurately the PSA reflects the plant as characterized in the FSAR. In Section 2.1 the system success criteria for responding to the various initiating events are covered. Section 2.2 is an evaluation of the support system requirements identified in the PSA for the various systems. In Section 2.3 assumptions regarding the configuration of the systems and human actions for both normal and emergency operations are discussed.

Section 3 contains the review of the application of PRA methods to the analysis. Section 3.1 is a discussion of the Initiating Event analysis, Section 3.2 contains the review of the event trees, and the system modeling is reviewed in Section 3.3. The quantification process is reviewed in Section 3.4, and the defining of plant damage states is discussed in Section 3.5. An overview of the dominant sequences is in Section 3.6.

Section 4 is a review of the PSA documentation, and Section 5 is a discussion of special topics and insights regarding the PSA. Section 6 is a review of the Fire Events analysis. Conclusions are in Section 7.

Review comments in Sections 2 through 4 of this report are categorized into three categories:

A. **Insights and Important Assumptions.**

B. **Review Findings.**

C. **Potential Problems Resolved.**

A different format was followed for the review of the Fire Events Analysis (Section 6).

Responses from HLP to all items in cagetories B and C are summarized following discussion of the subject items. HLP responses are included in Appendix 3 (Appendices 4 and 5 for HRA related responses and Appendix 6 for Fire Analysis issues) and labeled as IE1, IE2, etc., for "inadequately explained" items (category B) and PP1, PP2, etc., for "potential problems" (category C). This labeling scheme was developed by HLP in their response to SNL's initial list of issues and concerns transmitted to the licensee. It has been preserved here to document the association of the material in the appendices with HLP's written responses to SNL's review comments.

All issues raised in the review have been resolved to the satisfaction of the reviewers. Conclusions regarding the issues, and the results of the PSA are discussed in Section 7.

1.1 Methodological Overview

The methodology used in the STP PSA is referred to as a "large event tree - small fault tree" technique. This methodology, developed by PLG Inc., emphasizes the development of very large accident sequence event trees with many detailed top events or split fractions in the PLG terminology. Each event tree top event is modeled by a single independent logic model such as a fault tree or block diagram. This process is significantly different than the methodology employed in NUREG-1150 [4] and other NRC sponsored risk analyses. The NRC programs use what is described as a "small event tree - large fault tree" approach, where relatively simple event trees are developed to describe accident sequences, and extensive, highly dependent fault trees are developed to model the top events.

The PLG methodology does not model dependencies between systems and components explicitly in the top event or system models. Support systems and even operator actions are included as top events in the event trees along with front line systems. Each path through a particular event tree defines a unique sequence of events, and dependencies between events in the same sequence are handled by developing a model for each event which is dependent on any preceding event in the sequence. For example, if a particular sequence includes loss of electrical power as one top event and loss of the Auxiliary Feedwater System (AFWS) a subsequent top event, then a fault tree for loss of AFWS given loss of electrical power is developed. This is in contrast to the typical NRC method where event trees define combinations of front line system failures. The NRC method models system dependencies by developing a fault tree for each front line system with support system fault trees linked or attached to the front line trees.

The two methods result in very different representations of final accident sequences which can render comparisons of results between studies very difficult. The NRC method propagates basic event faults from the system fault trees through the event trees to the sequence end states. It does this by first linking support system fault trees to front line fault trees, then merging the appropriate front line trees for each sequence, and then using Boolean reduction to arrive at a unique sequence expression with minimal cut sets of basic events. The PLG technique passes no basic event information from the system level models to the event trees, but rather each top event is quantified separately and the resulting value (or distribution for the uncertainty quantification) is propagated through the event tree model.

The result is that accident sequence models look very different between the two methodologies. PLG accident sequence models have no cut set or basic event representation, but are combinations of split fractions (top events) which have been modeled specifically to account for the relationships between the top events for each sequence. The NRC method yields sequence expressions in the form of Boolean equations with cut sets of basic events from the system fault trees.

Because of the fundamental differences between the methods, results must be compared carefully. A direct comparison between sequences from the two methods is not always possible. Comparisons must be made between similar types of accident sequences (e.g., station blackout). Importance measures cannot be directly compared between methodologies as well, because of the different techniques of propagating basic event failures through the accident sequence analysis.

The methodology incorporates uncertainty of basic events and initiators in the quantification of sequence frequencies. However, as stated above, basic event information is not directly incorporated into the final sequence model. Each top event or split fraction on the event tree is quantified, using the uncertainty distributions of each basic event in the tree. The result is that an uncertainty distribution is generated for each split fraction. These top event level distributions are treated as independent, since the underlying fault trees were developed as fully independent of one another. Each sequence is quantified by multiplying the appropriate split fractions probabilities and initiating frequencies together. Uncertainty is propagated by randomly sampling each split fraction's distribution with a Monte Carlo routine and repeating the sequence calculation for each observation to generate an uncertainty distribution of the sequence frequency. While Monte Carlo sampling was used, there appears to be no reason why Latin Hypercube Sampling (LHS), a stratified Monte Carlo sampling algorithm employed in NUREG-1150, could not be used here. However, the computational demands of the PLG method are sufficiently low so as not to require the benefits of efficient sampling techniques.

Other differences exist, including common cause failure modeling, methods of sampling of uncertainty distributions, and failure rate values. However, much of the work PLG has done on common cause failures has been incorporated into the common cause analysis of NUREG-1150. In addition, many of the PLG basic event failure rates share common industry data with the NUREG-1150 data base. Differences between NUREG-1150 and the STP PSA regarding failure rates for similar components may arise. However, this last difference is more indicative of analyst choice or interpretation of data rather than fundamental methodological differences.

The level of detail for the system models is at least consistent with the level achieved for NUREG-1150 and, in some cases, is more detailed. Safety system trains were modeled by each significant component in the train (e.g., pumps, valves, pressure transmitters, strainers). Various failure modes for each component were modeled as appropriate. The analysis and modeling of operator actions was also done at a level of detail consistent with the hardware modeling.

It should be noted that the purpose of this review is not to evaluate the validity of the PLG methodology for PRA. Both the NUREG-1150 and the PLG methods can produce correct results when applied properly. The purpose of this review is to evaluate the quality, thoroughness, and accuracy of the STP PSA analyses and to assess the legitimacy of the results.

1.2 Limitations of the Analysis

The STP PSA represents a detailed Level I risk analysis. The sophistication of the various models and analyses is generally consistent with state-of-the-art PRA practices. But as such, this analysis has limits of scope which are characteristic of the state of the art for PRA. Areas and issues not treated in a detailed manner in PRA include:

- Partial Failures
- Design Adequacy
- Adequacy of Test and Maintenance Practices
- Effect of Aging on Component Reliability and Break-in Phenomena
- Adequacy of Equipment Qualification
- Environmentally Related Common Cause
- Similar Parts Related Common Cause (in different systems)
- Sabotage

A further limitation of the STP PSA, which is consistent with current PRA practice, is the steam generator tube rupture initiator (SGTR). The STP PSA considered only single tube ruptures. Multiple tube rupture events have not been considered in even the most recent PRAs.

2.0 PLANT ASSUMPTIONS

This section of the report summarizes the review of the plant model to which PSA techniques were applied.

A great deal of effort was put forth in the PSA to understand plant systems. Section 5.4 of the PSA and the System Descriptions in the PSA provide excellent details of system operations, limitations, interfaces, and assumptions used to create risk models. The event sequence diagrams of Section 5.4 are well thought out and useful.

2.1 Success Criteria

Criteria of special importance are discussed in this section are they relate to system success.

2.1.1 Transients

A. Insights and Important Assumptions.

It is conservatively assumed that main feedwater is isolated following reactor trip. [Reference 1, Pages 5.4-10, 5.4-12, and 5.4-28]

It is conservatively assumed that steam dump utilizing the turbine bypass system is not available following reactor trip. [Reference 1, Page 5.4-28]

Criteria for Reactor Coolant Pump (RCP) seal cooling are provided, including the ability to utilize the positive displacement charging pump powered from the Technical Support Center (TSC) diesel generator given isolation of letdown. [Reference 1, Pages 5.4-13 and 5.4-35] Seal failure is assumed to result in a small LOCA which is equivalent to a hole 0.5 to 2 inches in diameter. [Reference 1, Pages 5.4-35, and Section 5.4.6, definition of small LOCA] Using the Moody Model as described in Reference 3, a two-inch hole discharges about 240 lbm/sec (water); Table B.3 of NUREG-1150, Reference 4, indicates that for a total of three RCPs using older design seal O rings, the leak rate can be substantially greater than 240 lbm/sec. The PSA addressed this concern by performing a sensitivity analysis on seal leak rate. Using a leak rate of 1900 gpm (approximately equal to the maximum RCP leak rate in NUREG-1150), the overall core melt frequency increased by only 2%. [Reference 1, Section 2.2.3]

The PSA did consider both pressure and temperature limitations on the use of RHR. [Reference 1, Page 5.4-17]

To maintain hot standby for an extended period of time, makeup water to the Auxiliary Feedwater Storage Tank (AFWST) must be provided. This requirement was factored into the PSA. [Reference 1, Page 5.4-27]

The PSA recognizes that an Engineered Safeguard Features Actuation Signal (ESFAS) isolates normal charging and letdown but does not isolate seal injection. [Reference 1, Pages 5.4-30 and 5.4-35]

A good discussion of how transients can progress to Loss of Coolant Accidents (LOCAs) was provided. [Reference 1, Pages 5.4-30 and 5.4-40]

The PSA accounts for the need to depressurize the primary system if a transition from hot standby to RHR cooling mode is desired. [Reference 1, Pages 5.4-18] Depressurization can be achieved by spray, control of makeup and letdown, or use of primary PORVs. It is implicit in the PSA, that during cooldown, pressurizer heaters are not required to maintain subcooling margin and allow use of RCPs. Ambient heat losses from the pressurizer and insurge of primary water to compensate for primary thermal contraction should not decrease pressure significantly when compared to the decrease in saturation pressure as primary temperature is reduced.

Should a transient event change to a small LOCA, High Head Safety Injection (HHSI) will be required. [Reference 1, Page 5.4-16] For sufficiently small LOCAs, eventual recirculation from the sump will require high head pumps given the inability to sufficiently depressurize the primary. The high head pumps pull directly from the sump during recirculation. Decay heat removal and containment cooling are provided by Reactor Containment Fan Coolers (RCFCs), not by the RHR heat exchangers. [Reference 1, Page 5.4-8 and 5.4-19] Containment cooling is discussed more fully in Section 2.1.8 of this report.

The discussion of transients in Section 5.4 of the PSA provides good insight into required operator actions. For example, following a normal trip with no transition to a LOCA, the operator must: control letdown and makeup, control main feedwater if available or auxiliary feedwater if actuated, control cooldown with turbine bypass steam dump or steam generator PORVs, control RCS pressure, borate as required, and initiate RHR if return to power is not an option.

B. Review Findings.

Pressurized Thermal Shock (PTS) is of concern following a reactor trip if turbine trip fails and any Main Steam Isolation Valve (MSIV) fails to close. PTS is a possibility if the operator fails to manually throttle high head injection to maintain primary pressure within allowable limits as primary temperature decreases during the uncontrolled cooldown. [Reference 1, Pages 5.4-16 and 5.4-32] Numerical values for the failure of the operator to throttle high head injection and for the subsequent conditional probability of vessel failure from PTS could not be located in the PSA. [Reference 1, Table 5.4-5 does not provide a systems analysis reference section for Top Event VI, Reactor Vessel Remains Intact During PTS Challenge.] In item IE1 of Appendix 3, HLP justified a value for vessel failure during PTS of 1.1×10^{-4}. In item IE12 of Appendix 3, HLP indicated that throttling of HHSI is not possible.

Successful end states following a transient are: hot standby, hot shutdown with Residual Heat Removal (RHR) cooling the plant toward cold shutdown, or return to power. There appears to be some confusion in nomenclature; numerous statements appear to refer to hot standby as hot shutdown [Reference 1, Pages 5.4-27, 5.4-29, 5.4-37.] In hot shutdown

RHR can be in operation; RHR cannot be in operation during hot standby if the definitions of Table 1.2 of Reference 5 are followed. The nomenclature in the PSA should be consistent with that in the Technical Specifications. In item IE2 of Appendix 3, HLP agreed with the recommendation and will resolve the confusion between hot standby and hot shutdown in the next revision of the PSA.

C. **Potential Problems Resolved.**

Successful feed and bleed requires at least one train of High Head Safety Injection (HHSI) and manual opening of both pressurizer PORVs before steam generator dryout. [Reference 1, Pages 5.4-19 and 5.4-29.] High head charging pumps are not necessary for feed and bleed because the secondary water inventory in the steam generator provides for heat removal during the first 30 minutes of the transient after which decay heat is sufficiently low to allow depressurization of the primary system with the PORVs and makeup with HHSI. Section B.1 of Reference 1 claims that over one hour is available before steam generator dryout. A key parameter affecting time to dryout is the number of full-power seconds between loss of feedwater and reactor trip. Reactor trip on low level will probably result in dryout in about 30 minutes. If credit for earlier reactor trip on over temperature delta T can be assured, dryout may not occur until after one hour. During the November meeting HL&P agreed to resolve this issue. [6] As provided in item PP1 of Appendix 3, HLP has reduced the estimated time to steam generator dryout from over one hour to 34 minutes which still allows sufficient time for operator action as quantified in the PSA.

2.1.2 Large LOCAs

A. **Insights and Important Assumptions.**

A large LOCA is a major breach in the primary system piping that rapidly depressurizes the primary system. As primary fluid flashes, both water and vapor blowdown through the break with incomplete phase separation, and the vessel retains little water until Emergency Core Cooling System (ECCS) injection occurs. The PSA categorizes breaches greater than a six-inch diameter equivalent as a large LOCA. [Reference 1, Page 5.4-143.] This is a reasonable definition for a large LOCA, because at normal system pressure a six-inch hole discharges about 2200 lb/sec (water), [3] and the maximum ECCS injection rate from one train of HHSI and Low Head Safety Injection (LHSI) is 4000 gpm or 560 lb/sec with a completely depressurized primary [Reference 2, Figure 15.6-54.] Thus, a six-inch hole exhibits the characteristics of a major breach: rapid depressurization, emptying of the vessel, and the need for LHSI.

The PSA correctly accounted for both injection and recirculation of ECCS following all LOCAs.

B. **Review Findings.**

The PSA assumes that accumulator injection is not required following a large LOCA. [Reference 1, Pages 5.4-143.] This assumption needs to be justified. During the November 1989 site visit, HL&P agreed to address this item by either documenting the acceptable ECCS performance without accumulators or by adding a requirement for accumulator injection in the follow-on Level II PSA.[6]. In item IE3 of Appendix 3, HLP committed to include accumulators in the plant model for the level II PRA. Furthermore, HLP estimated that the effect of this additional requirement would have negligible impact on core damage frequency, which is consistent with NUREG-1150 accumulator models.

The large LOCA event tree does not address the effect of failure to isolate containment on the ability to reflood the core. If the containment pressure is lower than the minimum back pressure used in the LOCA licensing analyses, reflood of the core occurs at a lower rate. [Reference 6, Sections 6.2.1.1.1.6 and 6.3.3, and Figure 6.2.1.5. Reference 7, Section 6.2.1.5.] In item IE4 of Appendix 3, HLP justified the assumption that the effect of lower containment back pressure has negligible effect on the ability of the ECCS to prevent gross core damage. Even though the peak clad temperature may reach approximately 2510°F, well above the LOCA licensing limit of 2200°F, it is well below the zirconium phase transition temperature of 2900°F.

The PSA does not address long term switch over from cold to hot leg recirculation to avoid boron precipitation at the bottom of the core, thus blocking the flow of cooling center. In item IE5 of Appendix 3, HLP justified excluding this action since it has negligible impact on core damage frequency.

2.1.3 Medium LOCAs

A. Insights and Important Assumptions.

A medium LOCA covers a range of breach sizes between a large and a small LOCA. At the upper end of the range, a medium LOCA is like a large LOCA. At the small end of the range, a medium LOCA is like a small LOCA where injection does not utilize LHSI.

The PSA categorization of breaches between two and six-inch equivalent diameter as medium LOCAs is reasonable. [Reference 1, Page 5.4-129.] LHSI would never be activated for a two-inch break since at 300 psia (LHSI shutoff) one HHSI train can inject 1200 gpm (168 lb/s) while the break flow would only be about 100 lb/s (water) using Moody's model. [Reference 2, Section 6.3 and Figure 15.6-54, Reference 3.] It is assumed in the PSA that no steam generator heat removal is required to remove decay heat, due to enthalpy losses out the break. This is a valid assumption. At 2500 psig (safety valves setpoint) a two-inch hole relieves 240 lb/s (water), and 1.7×10^5 Btu/s or 110 lb/s (steam) and 1.2×10^5 Btu/s. [Reference 3, Reference 8.] The change in enthalpy of 1.2×10^5 Btu/s can match decay heat at about 300 seconds after reactor trip [Reference 2, Figure 6.2.1.1-18.] During the first 300 seconds the excess decay heat would heat up the primary by about 15 degrees F at most, which would not saturate the primary.

B. Review Findings.

The PSA assumes that accumulators are not needed to mitigate a medium LOCA. The resolution of this item is discussed in Section 2.1.2 along with large LOCAs.

2.1.4 Small LOCAs

A. Insights and Important Assumptions.

A small LOCA requires HHSI for makeup and also requires steam generator cooling. Phase separation in the vessel occurs following a small LOCA if the RCPs are tripped. Breaches small enough to be handled by the normal Chemical and Volume Control System (CVCS) are categorized as transients. The PSA categorizes breaches between 0.5 and two-inch equivalent diameter as small LOCAs. [Reference 1, Page 5.4-109.] Based on Table 9.3-9 of Reference 2, the CVCS can match a leak of about 150 gpm (hot fluid) in excess of 100 gpm normal letdown since the maximum CVCS injection is 230 gpm charging plus 20 gpm seal injection. 150 gpm (hot fluid) is 14 lb/s. At normal primary pressure a 0.5 inch hole will discharge about 15 lb/s. [3] Even if reactor trip on low pressure should occur no ESFAS actuation will occur since CVCS makeup can exceed loss through the hole above the ESFAS low pressure trip setpoint of 1850 psig. [5] Thus, 0.5 inches is an appropriate lower limit for small LOCAs. A two-inch upper limit for a small LOCA is acceptable. However, the details of primary to secondary cooling vary for different sizes of small LOCAs. For example, with steam generator cooling, the primary temperature will approximately equal the secondary temperature, about 550°F. Saturation pressure at 550°F is about 1000 psia. At 1000 psia one train of HHSI supplies about 700 gpm or 98 lb/s, but a break of size two inches relieves water in excess of this HHSI injection rate at 1000 psia. Thus, for certain small LOCAs the primary system will depressurize to saturation, flashing will occur, and condensation cooling of the primary side in the steam generators will be required. [9] However, one train of HHSI will, indeed, mitigate such a small LOCA.

In the recirculation mode, for breaches in the lower end of the small LOCA size range recirculation cooling will be with HHSI. The PSA claims that in this situation, RCFCs can remove decay heat and cool containment. [Reference 1, Page 5.4-121.] For high end small LOCAs, the primary system will depressurize to the point where LHSI can be used, which provides for heat removal through the RHR heat exchanger. Containment cooling is discussed in Section 2.1.8 of this report.

Given a small LOCA without Turbine Trip or MSIV closure, concerns related to PTS are handled as they were for a transient. [Reference 1, Pages 5.4-110 and 5.4-124.]

B. Review Findings.

The PSA does not discuss breach of an instrument tube as a unique small LOCA. This breach would be special because its location would be below the core, whereas all other small LOCAs would occur in elevated piping.

If the RCPs were to be tripped following a small LOCA, an issue here is whether or not the small LOCA success criteria would apply to an instrument tube breach. Small LOCAs in elevated piping would drain the primary system until the water level dropped below the break. Steam would continue to escape out of the break, but the core would remain covered and subcooled natural circulation would keep the core cooled. An instrument tube breach would continue to drain the primary system. However, the small size of the instrument tube (probably 5/8 inch or less) should ensure that HHSI could makeup the loss and maintain subcooled natural circulation to the steam generators necessary. [9] That is, the generic small LOCA success criteria should cover instrument tube LOCAs. Instrument tube LOCAs should be addressed to ensure that they are covered within the generic small LOCA category. In item IE6 of Appendix 3, HLP provided justification for categorizing instrument tube breaks within the capacity of the CVCS; therefore, they are not LOCAs.

2.1.5 SGTR

A. Insights and Important Assumptions.

The description of a Steam Generator Tube Rupture (SGTR) accident in Section 5.4 of the PSA is very thorough.

The PSA conservatively assumes that core damage occurs if the primary system cannot be cooled to hot shutdown and RHR initiated. [Reference 1, Page 5.4-102.] It is possible to mitigate a SGTR by remaining in hot standby with secondary pressure below the steam generator PORV setpoint on the bad steam generator provided makeup to the AFWST is available.

The PSA conservatively assumes that primary pressure must be controlled with spray, auxiliary spray or primary PORVs during cooldown. [Reference 1, Pages 5.4-106 and 5.4-107.] Plant Emergency Operating Procedures (EOP) do cover cooldown following a SGTR without pressurizer pressure control or with a saturated primary [10,11].

2.1.6 V Sequence

A. Insights and Important Assumptions.

The V sequence is an interfacing systems LOCA that bypasses containment. It should be noted that the RHR pumps and RHR heat exchangers are inside containment at STP and thus rupture of their associated piping is not a potential initiator for the V sequence.

B. Review Findings.

There are four potential pathways for the interfacing systems LOCA. These involve the RCS hot and cold leg injection paths for each HHSI and LHSI pumps. The V sequence was not actually quantified in the PSA. It was screened out based on a comparison of the potential leak paths at STP to the potential leak paths at Seabrook station.

The frequency of the V sequence in the Seabrook PSA[12] was calculated to be 3.4E-8/yr. Each potential leak path at Seabrook has only two pressure barriers (either two check valves or two closed MOVs). It was claimed in the STP PSA that each potential leak path at STP has at least three pressure barriers (either three high pressure check valves or two high pressure check valves and a closed MOV). Based on this, it was argued that the frequency of a V sequence at STP would be less than the already low frequency for Seabrook.

There are two problems with this argument. First, one potential leak path at STP, the RCS cold leg LHSI system injection path, has only two check valves which can serve as high pressure barriers. The assertion that the LHSI cold leg path has three such check valves which can be treated as high pressure barriers is incorrect. The second problem with comparing STP to Seabrook is that in the Seabrook V sequence model, operator actions to mitigate the sequence were incorporated into the model. So the argument to screen out the V sequence at STP based solely on a comparison of hardware configurations with Seabrook is incorrect.

HLP concurred that there was a problem with the V sequence model as presented in the PSA. A new analysis of the V sequence is presented as item IE7 of Appendix 3. A schematic of the injection lines is included in the appendix.

The new analysis focuses on failures in the ECCS LHSI piping, as did the original analysis, since failures in the HHSI paths are much less likely because of the presence of closed, high-pressure rated MOVs, and because of the higher pressure rating of the HHSI system. This analysis is rigorous and detailed. However, concerns and questions regarding this analysis are listed below:

1. HLP presented three values for the V sequence frequency which correspond to three different mitigation scenarios.

   - No mitigation action taken (1.73E-06)
   - No specific guidance given to operators (1.71E-07)
   - Specific guidance given to operators (2.28E-08)

   The first result is quite high compared to NUREG-1150 results for Surry (3.8E-7/yr) and Sequoyah (2.7E-7/yr), and the second result is comparable to NUREG-1150. The third result is comparable to Seabrook.

2. The new analysis uses a mean frequency of random failure of a high pressure check valve of 4E-8/hr, compared to 5.4E-7/hr in the PSA data base. The later value corresponds to data item ZTVCOL in the PSA data tables.

3. The new analysis incorporates operator actions to mitigate the impact of an interfacing systems LOCA. These operator actions are evaluated within the context of a good discussion of the temperature and pressure instrumentation available to the operators as indicators of the existence of a leak. The analysis estimates that operators will successfully isolate the leak 90% of the time without detailed procedural guidance, and 99% of the time with such guidance. The values for the operator actions for these two scenarios (guidance versus no guidance) appear to be reasonable. Such a discussion would be helpful in validating this analysis.

4. The new analysis does not consider the possibility that the operator successfully acts to close the necessary MOV to mitigate the leak, only to have the MOV fail to close on demand. Since no data is provided for failure of the valve to close, it appears that the new analysis assumes that failure of the valve to close on demand is much less likely than failure of the operator to initiate the closure action. In most circumstances, this assumption would be valid, but it requires further justification in this instance. The valve in question (MOV RH-0031) may not be able to close against reverse flow unless its torque switches are set to allow for this flow. This is an important point since without successful mitigation, the V sequence frequency is comparable to other dominant core damage sequences for the STP PSA and should not be screened.

Table 5.4-31 of the PSA is entitled "Piping Systems Connected to the RCS". This table fails to include the four-inch letdown line which penetrates containment. This line is not of concern for the V sequence because flow orifices are present in the line inside containment which limit flow through a line break outside containment to within the CVCS makeup capability. [Reference 2, Section 15.6.2.2.] A break in the letdown line outside containment is thus categorized as a transient, not a LOCA. This point should be discussed in the PSA. In item IE8 of Appendix 3, HLP verified that a letdown line break outside of containment is not a LOCA due to the presence of flow limiting orifices.

2.1.7 ATWS

A. Insights and Important Assumptions.

The discussion in the PSA for the Anticipated Transient without Scram (ATWS) sequence is very thorough. The success criteria employed is consistent with current ATWS analysis. The success criteria require two ATWS trains, and all primary safety valves, and emergency boration and ultimate makeup.

Vessel failure is assumed to not occur if ASME level C service conditions are maintained which correspond to an upper limit on primary pressure of 3200 psig. If 3200 psig primary pressure is exceeded, a small LOCA is postulated to occur. [Reference 1, Page 5.4-42.] The PSA requires boration given failure of rods to insert, to mitigate the ATWS. [Reference 1, Page 5.4-41.] Boration is necessary to reduce power and lower pressure to allow for inventory makeup.

2.1.8 Containment Cooling

B. Review Findings.

The PSA implies that spray injection and spray recirculation are not required for containment integrity, but are helpful for fission product removal. [Reference 1, Page 5.4-144.] Containment pressure will exceed the calculated pressures of Section 6.2, Reference 2, if there is no spray injection, but apparently it would not exceed the design value of 56.5 psig. However, the effect of no containment spray injection on containment pressure is not explicitly discussed. In item IE9 of Appendix 3, HLP references a calculation which verified that a lack of containment spray will not threaten containment integrity.

Without spray recirculation, thermodynamic equilibrium between the sump water and the containment atmosphere is less closely achieved. This means that the sump water may be evaporating, which is acceptable because adequate NPSH for the ECCS pumps is available if the vapor pressure for the sump water is as low as the containment pressure from vapor and air. [Reference 2, Section 6.3.2.2.] Spray recirculation removes no energy from containment at STP, but does help establish thermodynamic equilibrium.

Section 5.4 of the PSA states that during recirculation, either one RHR heat exchanger or two RCFCs can maintain containment integrity and match decay heat. [Reference 1, Pages 5.4-148, 5.4-149, 5.4-76.] These criteria are in conflict with those of Section 16 of the PSA which states both one RCFC and one recirculation heat removal path are required. [Reference 1, Page 16.1-5.] Also, Section 16 implies that recirculation always removes heat. This is not true at STP when recirculating with HHSI pumps; only recirculation with LHSI pumps utilizes the RHR heat exchangers. The discrepancies between Sections 5.4 and 16 of the PSA are resolved in item IE9 of Appendix 3. HLP resolved the discrepancy by stating that core damage sequences categorized as "containment heat removal only" were conservatively binned into the plant damage state "no containment heat removal and fission product scrubbing". This binning assumption will be evaluated during the level II PRA. HLP agreed that HHSI recirculation alone cannot provide heat removal. Two RCFC's are required to remove heat and this was correctly modeled in the PSA.

Minimum containment cooling success criteria for recirculation cooling is either one LHSI loop cooling sump water or two RCFCs cooling the containment atmosphere. The PSA does not reference a basis for this, but the following rough calculation supports these criteria:

Assume that sump water temperature is 300°F (the maximum design temperature of ECCS pumps [Reference 2, Table 6.3-1]). Assume that containment sprays are not functioning. This would result in sump temperatures higher than the containment atmospheric temperature. The sump water would be evaporating into the containment atmosphere, which would have a pressure of 68 psia, slightly below the containment design pressure of 71.2 psig. At 68 psia, the partial pressure of air is about 19 psia, so the partial pressure of steam is about 49 psia. The saturation temperature of steam at 49 psia is 280°F. The performance specifications for the LHSI and RCFC at the above conditions are obtained from Reference 6, Figure 6.2.1.1-3 and Table 6.2.11-5:

LHSI (one loop) - Removes 200 x 10^6 Btu/hr from 300°F sump water

RCFC (two units) - Removes 220 x 10^6 Btu/hr from 280°F atmosphere.

The decay heat from the reactor would not reach the lower heat removal rate for these two performance specifications (200 x 10^6 Btu/hr) until 4000 s after reactor trip [Reference 2, Figure 6.2.1.1-18]. If it is assumed that recirculation cooling is initiated at 1200 s after reactor trip (a reasonable time based on information in the FSAR), then the containment conditions at the start of recirculation would be 235°F with a decay heat rate of 280 x 10^6 Btu/hr [Reference 2, Table 6.2.1.1-10 and Figure 6.2.1.1-18]. There would be an increase of heat in the containment for the next 2800 s. If this mismatch is conservatively assumed to be 80 x 10^6 Btu/hr, a total of 62 x 10^6 Btu would be added to the containment before the heat removal rate of the containment systems would equal the decay heat rate. This buildup would be acceptable because 190 x 10^6 Btu would be required to increase the atmospheric temperature of the containment from 235°F to 280°F with saturated steam.

Equipment operability under these minimum containment cooling conditions is not discussed in the PSA. In item IE9 of Appendix 3, HLP provided justification for minimum containment cooling requirements as assumed in the PSA.

It is claimed in the PSA that a hole in containment greater than or equal to three inches in diameter will not allow the containment to pressurize. [Reference 1, Page 5.4-73.] The basis for this claim is not clear. At a design pressure of 71.2 psia, a three-inch hole will relieve about 2.2 x 10^4 lb/hr of saturated steam [based on equations in Reference 13]. If it is assumed that all decay heat generates steam and an enthalpy of phase change of 900 Btu/lb is used, this relief rate can match 1.98 x 10^7 Btu/hr of decay heat. However, this level of decay heat is not reached until about 10^6 seconds after reactor trip [Reference 2, Figure 6.2.1.1-18]. The PSA does not justify the three-inch limit. In item IE11 of Appendix 3, HLP indicated that the three inch limit is based on using an estimated failure pressure of 150 psia instead of the design pressure of 71.2 psia. By the time 150 psia is reached the decay heat is sufficiently low so that a 3 inch hole can prevent further pressure increase. Furthermore, at STP all penetrations categorized as greater than 3 inches are in fact greater than 18 inches, thus providing significantly greater relief.

In accident scenarios in which recirculation from the sump is available, but with no containment heat removal via RHR heat exchangers or RCFCs, core melt is assumed to occur prior to containment failure. [Reference 1, Page 5.4-121, 5.4-135,5.4-146.] This is reasonable using 300°F as the design limit for ECCS pumps since as previously discussed the 300°F limit should be reached before the containment design pressure is reached. This point should be clarified in the PSA. In item IE9 of Appendix 3, HLP provided information to support this assumption.

The PSA does not consider the possibility for early containment failure except for failure-to-isolate the containment. [Reference 1, Section 5.4.4 and Table 16.1-6] Early containment failure occurs before or during core melt and causes faults other than failure-to-isolate containment. It is stated in NUREG 1150 [4] that early containment failure at large dry PWR containments is of low likelihood. However, direct containment heating following high pressure core melt or in-vessel steam explosion can cause early containment failure. These points should be mentioned in the Level I PSA but do not have to be substantiated until the Level II PSA is completed. In item IE10 of Appendix 3, HLP committed to evaluate these early failure modes of containment in the Level II PRA.

2.2 Support System Requirements

Tables 5.3-1 and 5.3-2 of the PSA summarize intersystem dependencies. The system descriptions appended to the PSA provide more details on support interfaces.

2.2.1 Electric Power

A. Insights and Important Assumptions.

System dependencies on electric power for motive power appear to be completely identified. The 4160 Vac system includes the 480 Vac system. [Reference 1 system description 1 assumption J6.] Sources of electric power consist of: offsite power, the three 4160 Vac 1E trains including 480 Vac, the four DC 1E trains, and the four Vital 120 Vac trains.

The following requirements were correctly identified in the PSA:

- Pressurizer PORVs require DC to open.

- Pressurizer PORV block valves require 480 Vac to close.

- Steam Generator PORVs use hydraulic actuators and require 480 Vac. They also require 120 Vac and the Qualified Display Processing System (QDPS).

- Auxiliary Feedwater train D requires DC power to open isolation valves. No AC power is required for train D. Trains A, B, and C require 4160 Vac for pump motors and 480 Vac for isolation valve motors; DC power is required to close the circuit breakers to start the pumps. (4160 Vac motors are across-the-line starting and do not use motor starters.)

- MSIVs fail closed on loss of DC.

- Turbine bypass valves require DC to open.

- The CVCS centrifugal starting pumps require 4160 Vac for motors and DC for closing circuit breakers. The CVCS positive displacement pump motor requires 480 Vac. Valves require 480 Vac.

- The HHSI and the LHSI require 4160 Vac for pump motors and DC for circuit breakers. All motor operated valves (MOVs) are correctly aligned for injection but 480 Vac is required to operate valves when switching to recirculation.

- The Containment Spray System (CSS) requires 4160 Vac for pump motors, 480 Vac for valves, and DC for circuit breakers.

- The RCFCs require 480 Vac for fan motors and DC for circuit breakers.

- Containment isolation requires 480 Vac and DC.

- RHR, Component Cooling Water (CCW) and Essential Cooling Water (ECW) require 4160 Vac for pump motors, 480 Vac for valves, and DC for circuit breakers.

- Essential chilled water requires 480 Vac for pump motors. The PSA also identifies a requirement for 1E DC. However, this may not be necessary. These motors use motor starters in a motor control center and the AC power for closing contactors is derived from a stepdown transformer in the 480 Vac supply [wiring diagram 9ECH0701]. Only if circuit breakers upstream of the contactors are open is 1E DC required to close them.

2.2.2 Instrumentation and Control

The electrical requirements for Instrumentation and Control (I&C) were reviewed for both automatic control, and instrumentation as required for manual control.

A. Insights and Important Assumptions.

The following I&C dependencies for automatic actuation were correctly identified in the PSA:

- Automatic actions to trip the reactor and actuate safety equipment do not require control power. The Reactor Protection System (RPS) and the ESFAS both de-energize to trip except for the final bistable for initiating containment spray. [Reference 2, Section 7.3.1.2.2.1.]

- 1E DC is required for closing and tripping circuit breakers in 4160 Vac and 480 Vac circuits.

- 1E DC is required for diesel generator field flashing and emf control (The diesel generators do not use dedicated batteries, as verified in Reference 6.)

- 1E DC is required for the ESF Diesel Generator Load Sequencers.

- AC for 480 Vac motor starters in Motor Control Centers (MCC) is derived from the 480 Vac distribution to the MCC via a stepdown transformer.

The following I&C dependencies for reading instrumentation in conjunction with subsequent manual actions were correctly identified in the PSA (power for actuated components was discussed in the previous section):

- Solid State Protection System (SSPS) is necessary to reset ESFAS.

- SSPS requires 120 V vital AC.

- QDPS and associated inputs are needed to monitor plant conditions.

- QDPS requires 120 V vital AC.

- For control of Auxiliary Feedwater, QDPS and DC power are required for train D; QDPS and 120 Vac are required for trains A, B, and C.

- Switching ECCS from injection to recirculation mode requires SSPS for actuation on low RWST level.

- Essential chilled water needs QDPS for ECW valves on chillers.

- Other systems need I&C to provide information required for manual control; however, the ability to manually control these systems is not critical. Such systems include: CVCS, CCW, ECW, RHR heat exchangers/bypass, and boron addition.

B. Review Findings.

It was perceived in the review of the PSA that HHSI can be throttled, and that for monitoring of HHSI, QDPS can be utilized. Without information on pressurizer level, throttling of HHSI as required (for example to avoid PTS) is not possible. This dependence is not identified in Table 5.3-2 of the PSA. In item IE12 of Appendix 3, HLP stated that HHSI cannot be throttled due to a "lock-in" feature in the HHSI discharge valves control circuitry; thus, the ability to monitor pressure level for the purpose of throttling HHSI is not of concern.

2.2.3 HVAC/Room Cooling

Room cooling is required to maintain equipment within design temperature limits. Heat sources within a room include: hot fluid, motors, and electrical switchgear. Heat removal is provided by building Heating Ventilating and Air Conditioning (HVAC) systems or by dedicated room coolers.

The requirements for safety grade cooling as discussed in section 9.4 of Reference 2 were compared to the dependencies indicated in Tables 5.3-1 and 5.3-2 of the PSA.

A. Insights and Important Assumptions.

The following dependencies for HVAC/Room Cooling were correctly identified in the PSA:

- Control room HVAC Requires Essential Chilled Water to cool the Air Handling Units (AHU).

- Essential Chilled Water requires ECW for a heat sink.

- Electrical switchgear requires the Electrical Auxiliary Building (EAB) HVAC.

- EAB HVAC requires Essential Chilled Water to cool AHUs. (Once through EAB HVAC is discussed in Section 2.3.2 of this report.)

- CCW pump rooms require supplementary coolers cooled by ECW. This is an additional dependence of CCW on ECW besides the need for CCW heat exchanger cooling. System Description 7 of the PSA for CCW indicates that ECW is necessary for both CCW heat exchanger cooling and for supplementary coolers.

- Diesel Generator rooms require once through ventilation using supply fans and intake/exhaust louvers. This dependence is not explicitly identified in Table 5.3-1; however, System Description 1 of the PSA for electrical power verifies that this dependence is considered as part of the standby power system itself.

- The ECW pump rooms require once through ventilation using supply fans and intake/exhaust louvers. This dependency is included as part of the ECW system itself. [Reference 1, System Description 4, Section J.9.].

- AFW motor pump rooms require once through ventilation using supply fans and intake/exhaust louvers. This dependency is included as part of the AFW system itself. The turbine driven AFW pump room requires no room cooling. [Reference 1, System Description 9, Sections C and J].

B. Review Findings.

The CVCS pump rooms require supplementary coolers cooled by CCW. This is an additional dependence of CVCS on CCW besides lube oil cooling for the centrifugal charging pumps. System Description 10 Section C of the PSA for CVCS indicates CCW is required for cooling all CVCS pump rooms. However, Section 1, assumption 9 of this system description states that analyses performed by HL&P indicate loss of room cooling for the positive displacement pump is acceptable. This analysis should be referenced, because an important finding of the PSA is that RCP seal injection can be provided by the PDP powered off the TSC diesel generator following station blackout. In item IE13 Appendix 3, HLP summarized a calculation which justifies the assumption that PDP room cooling is not required.

C. Potential Problems Resolved.

ECCS pump rooms require Essential Chilled Water according to Reference 2, Section 9.4. This dependence is not included in Table 5.3-2 of the PSA for LHSI, HHSI, and CSS. Table 5.3-2 does indicate that the ECCS pump rooms require EAB HVAC. Based on Reference 6, this entry is not necessary since it evidently accounts for an indirect dependence of the pump motors on the EAB HVAC. The EAB HVAC is necessary for cooling the 4160 Vac power supply switchgear for the ECCS pumps, but this dependence is already included as part of the ECCS dependency on the 4160 Vac system.

System Description 10 for safety injection, assumption J-2, states with respect to ECCS pump room cooling "...it is assumed that room cooling is not necessary due to natural convection that will be available. [1]" This assumption is not justified. During the November 1989 site visit, HL&P stated that they are investigating this issue. [5] During a tour of the plant in November, it was noted that the ECCS pump rooms are open to the Fuel Handling Building. Also, the RHR heat exchangers are inside containment, not in the ECCS pump rooms as they are at some plants. Thus, heat removal requirements for these rooms may be possible by natural circulation alone but this claim must be substantiated.

The utility supplied information on this issue in a letter dated January 19, 1990 from S. D. Phillips, Support Licensing at HL&P. [24] In the letter, transient heatup analyses of the ECCS pump rooms were discussed. The analysis of most significance to the ECCS room cooling dependency issue is a study of the temperature profile of the pump rooms with no room cooling available, including the FHB HVAC system. The FHB and ECCS are linked by large passageways which could allow for significant air flow between the two volumes. The analysis also assumed no natural convection between the pump rooms and the FHB. Thus, the analysis conservatively looked at heatup in "sealed" ECCS pump rooms.

The analysis showed that an "enveloping temperature was reached in three days. [15]" Unfortunately, the letter did not state what this enveloping temperature was. If, for example, this temperature was 300°F (maximum operating temperature of the ECCS pumps), then this analysis could be flawed. Electrical and control components which are located in the pump rooms may have significantly lower maximum operating temperatures. If the analysis correctly accounted for the maximum operational temperature of these components, then the three-day time period required to reach this enveloping temperature provides a very long recovery time window. Loss of ECCS pump room cooling is most probably not important in this circumstance. However, if the maximum operating temperatures of the electrical and control components was not correctly incorporated into the analysis, then the issue of ECCS room cooling dependency would not be resolved.

In item PP2 of Appendix 3, HLP summarized a calculation which assumes no heat removal from the ECCS pump rooms and estimates that 200°F is reached after three days. This is acceptable for up to seven days for equipment operability.

2.2.4 Cooling Water

A. Insights and Important Assumptions.

This section discusses the requirements for direct cooling of equipment; room cooling was discussed in the previous section.

The following requirements were verified to be correctly considered by the PSA:

- Emergency Diesel Generators are cooled by ECW
- CCW is cooled by ECW
- Essential Chilled Water is cooled by ECW
- RHR Heat Exchangers are cooled by CCW
- RCFCs are cooled by CCW
- CVCS centrifugal charging pumps lube oil is cooled by CCW
- RCP seals are cooled by either seal injection or CCW
- RCP motors are cooled by CCW
- RCP pump thermal barriers are cooled by CCW
- Auxiliary feedwater pumps are self cooled
- The Positive Displacement (PDP) pump in CVCS is self cooled [Systems Description 10, Section I, Reference 1.]
- HHI, LHI and CSS pumps are all self cooled. [Reference 2 and Reference 6.]

2.2.5 Instrument Air

A. **Insights and Important Assumptions.**

Loss of Instrument Air (IA) is an initiating event because, among other things, it causes loss of main feedwater. The PSA does include loss of IA as an initiator. [Reference 1, Table 5.2.1.] This section reviews the impact of the loss of IA on mitigating systems. IA was not considered to be required for any mitigating system in the PSA; IA is not included in the system dependency Tables 5.3-1 and 5.3-2 of the PSA.

Section 9.3.1.3.1 of Reference 2 states that no safety components require air accumulators to function properly. This design feature means that loss of IA is not of concern for safety related components at STP. (At other plants where accumulators are required, loss of IA should be considered because without recharging, accumulators may leak through check valve failures.) IA is required for some non-safety components at STP. Air starting for DGs is provided by dedicated air compressors and storage receivers which are separate from the IA system. [Reference 2, Page 8.3-6 and page 8.3-24.]

Using Table 9.3-2 of Reference 2, the effect of loss of IA was examined for impact on the PSA. This review provided the following results:

- Main Steam System MSIVs Fail Closed (FC). This has no effect on the PSA since the PSA assumed main feedwater and turbine bypass are not available after reactor trip as discussed in Section 1.1.1 of this report.

- RHR heat exchanger valves Fail Open (FO) and heat exchanger bypass valves FC. This has no effect on the PSA.

- CCW radiation monitoring valves FC. This has no effect on the PSA.

- All air operated components in ECW, CVCS, control room HVAC, and EAB HVAC fail to safe position. This has no impact on the PSA.

- Diesel Generator ventilation dampers FO. This has no impact on the PSA.

- All air operated components in essential chilled water fail to safe position. This has no impact on the PSA.

- Cross connect valves in the AFW FC. This has no impact on the PSA since cross connection was not considered. [Reference 5]

- TBVs FC. This has no effect on the PSA due to no credit being given for steam dump after trip.

- Main feedwater flow control valves FC. Also, steam to pump turbines is lost since MSIVs FC. This has no effect on the PSA since no credit was given to main feedwater after trip.

- SG blowdown lines isolate. This has no impact on the PSA.

- ECW intake structure ventilation components fail to safe position. This has no impact on the PSA.

The assumption that IA is not required as an important mitigating system in the PSA appears to be correct.

B. Review Findings.

Loss of IA has no effect on the PSA model as long as no credit is given for main feedwater or for turbine bypass steam dump after a trip. A more complete discussion of the justification for not concluding IA in the plant model would clarify this point. In item IE14 of Appendix 3, HLP stated that justification for not modeling IA as a mitigating system is provided in the system notebooks which are part of the PSA.

2.3 System Lineups and Operations

This section highlights important aspects of the PSA related to standby system availabilities and off-normal lineups available to mitigate accidents.

2.3.1 Normal

A. Insights and Important Assumptions.

At power, standby system known unavailabilities are limited by the technical specifications. [5] Major asymmetries in train unavailabilities as modeled in the PSA are summarized in this subsection.

For AFW, train D has a different unavailability than trains A, B, or C because D is turbine driven, DC controlled, and A, B, and C are motor driven, AC controlled. Technical specification 3.7.1.2 of Reference 5 places more stringent operability requirements on trains B and C than on train A, (This is probably because A and D share the same ESF actuation channel A.) The PSA indicates that the failure rate for train A is higher than the failure rate for Train B or C. In particular, failure rates for A and B (or C) are respectively: 8.6×10^{-2} (split fraction CDF) and 5.1×10^{-2} (CDH). [System Description 9, Reference 1]

For ECW, the PSA assumes train A is running, C is standby autostart, and B is off but available for manual start. [System Description 4, Assumption J.5, Reference 1] Thus the failure rate for B is highest, and the failure rate for C is higher than for A. In particular, failure rates for A, B, and C are, respectively: 9.4×10^{-4} (W11), 1.3×10^{-1} (W13), and 9.6×10^{-3} (W14).

For EAB HVAC, the PSA assumes Trains A and B are running and Train C is on standby. Thus failure of Train C is higher than A or B. [System Description 6, Assumption J.1, Reference 1.] In particular, failure rates for A (or B) and C are, respectively: 6.8×10^{-4} (F11), 4.5×10^{-2} (F13).

2.3.2 Emergency

A. Insights and Important Assumptions.

Cross connection of AFW among steam generators was not considered as a possibility in the PSA. [6] This is a conservative assumption.

Feed and Bleed success criteria is based on Westinghouse calculations which justify the use of one HHSI train and both pressurizer PORVs. [Reference 1, Page 5.4-29] Credit for using only one PORV or vessel head vent is not given in the PSA.

RCP seal injection during station blackout is possible using the PDP charging pump powered by the TSC diesel generator. [Reference 1, Page 5.4-35]

ESFAS reset is required to throttle HHSI (to prevent PTS). [Reference 1, Page 5.4-14]

ECCS switchover from injection to recirculation is automatic.

Primary PORV motor operated block valves can be closed given failure of a PORV to reset. These valves are normally open. [Reference 1, Page 5.4-22] (Steam generator PORV block valves are manual valves, locked open.)

RCPs are tripped upon loss of CCW to bearing oil coolers to avoid vibration induced seal LOCAs. [Reference 1, Page 5.4-25]

AFW Storage Tank (AFWST) makeup is required to remain in hot standby. [Reference 1, Page 5.4-27]

Following an ATWS with inability to insert rods, boration is required. [Reference 1, Page 5.4-41]

On HHSI recirculation with no RCFCs, no containment heat removal is available. Operators can attempt to depressurize the primary system with the steam generator PORVs to allow LHSI recirculation and heat removal by RHR heat exchangers. [Reference 1, Page 5.4-69]

Following a SGTR, operator action is required to isolate the broken generator and cooldown to hot shutdown where RHR can be used. [Reference 1, Section 5.4.5] The PSA conservatively does not take credit for the following scenarios given SGTR:

- Primary depressurization without PORVs, spray, or auxiliary spray. [Reference 1, Page 5.4-106]

- Remaining at hot standby below setpoint of PORV on bad steam generator with makeup to AFWST. [Reference 1, Page 5.4-102]

- Using turbine bypass steam dump as a way to depressurize secondary. [Reference 1, Page 5.4-102]

- Isolation of the broken steam generator with other downstream valves if the MSIV fails to close. [Reference 1, Page 5.4-107]

B. Review Findings.

If normal EAB HVAC is unavailable because of a loss of cooling to the Air Handling Unit (AHUs), it is assumed that once through (smoke purge) operation of the EAB HVAC will prevent components from overheating. [Reference 1, System Description 6, Section B.6, E.6, J.3, and J.5] This is an important point. The PSA should reference the actual calculation justifying once through cooling with no AHU cooling. In item IE15 of Appendix 3, HLP highlighted sections of the PSA which justify the once through cooling mode of the EAB HVAC as being acceptable.

The System Description for AFW states that decay heat removal with one steam generator is acceptable provided that the PORV setpoint is reduced within 20 minutes after reactor trip to lower the steam generator temperature. [Reference 1, System Description 9, assumption J 2. and item B] The plant model implies that one steam generator supplied by its AFW pump can remove decay heat without use of its PORV. [Reference 1, Page 5.4-33] This difference in assumptions should be cleared up.

In item IE16 of Appendix 3, HLP stated that for removing decay heat, one steam generator without its PORV is acceptable, but the pressurizer PORV's are challenged to open. This challenge to the pressurizer PORV's is considered in the PSA model. For events requiring depressurization of a steam generator, the steam generator PORV is required and this is included in the PSA model.

3.0 PROBABILISTIC SAFETY ANALYSIS FOR STP

This section of the report summarizes the review of the application of PSA techniques to the South Texas Plant.

3.1 Initiating Events

A. Insights and Important Assumptions.

The PSA performed a comprehensive identification of initiating events. [Reference 1, Section 5.2] The following three methods were used to identify initiating events: Master Logic Diagram, Heat Balance Fault Tree, and Failure Modes and Effects Analysis. The final selection and grouping of initiating events is reasonable. [Reference 1, Section 5.2.4 and Tables 5.2-8]

The Failure Modes and Effects Analysis (FMEA) focused on plant specific support system failures of significance as initiating events. The FMEA was applied, to some degree, to all 212 STP systems and subsystems. The FMEA did not consider coincident, multiple failures among systems. However, such occurrences are sufficiently rare as to be eliminated from consideration. (The initiating phase of an accident can be defined as covering the time from the first event until reactor trip should occur, about ten seconds at most. The likelihood of subsequent failures occurring during this short interval is small. Failures following the initiating phase are modeled as mitigating system failures.)

B. Review Findings.

Minor comments on the identification of initiating events are as follows:

- High and medium energy line breaks and cracks should be discussed more completely as potential initiating events. LOCAs, main steam line breaks, and feedwater line breaks are considered; however, the PSA did not explicitly address other breaks such as one in the high energy steam line to the auxiliary feedwater train D drive turbine. Such events may be bounded by other events retained for detailed analysis as described in Section 5.2.4 of the PSA. In item IE17 of Appendix 3, HLP verified that such events are bounded by those retained for quantification.

- The PSA does not justify excluding core blockage as an initiating event. Tables 5.2-6 and 5.2-7 indicate this event was identified but screened from further analysis. [1] In item IE18 of Appendix 3, HLP verified the acceptability of screening core blockage from detailed analysis.

3.2 Event Trees

A. Insights and Important Assumptions.

The PLG technique uses the large event tree, small fault tree approach. This technique develops models for a system which reflect the effect of prior system successes and failures. Event tree linking is used to correctly select the appropriate combination of system models for a given accident sequence. That is, the ordering of split fractions (top events) in a particular sequence determines the appropriate system model to be used. Strictly speaking, a split fraction is the conditional probability of a system success or failure dependent on all previous system successes and failures. However, in the terminology of the PLG method, the term "split fraction" is used to denote the top events of the event trees.

The STP PSA contains four stages of event trees: two support and two frontline. The first stage event tree is for the electric power system, while the second stage event tree covers mechanical support systems. The third stage event tree models frontline systems through the early phase of an accident while the fourth and final stage event tree models frontline systems during the latter phase of an accident. Section 4.3.5 of the PSA summarizes event tree linking which is a complex but systematic process. The procedure, as described, does indicate how a given split fraction is properly quantified; that is, the procedure addresses all prior failures and successes which form pre-existing conditions that affect the particular fault tree to be selected for each system in a given accident sequence. Both support system dependencies and the effect of the initiating event on the split fraction quantification are described.

The event trees are very complex, but systematic because of the nature of the PLG technique. The PSA does an excellent job of describing the event tree development. The Event Sequence Diagrams (ESDs) which were developed as precursors to the frontline system event trees are extremely useful both as a development tool and as a road map for review. The PSA is careful to point out simplifying assumptions used in developing the event trees.

It is concluded that the STP event trees and the techniques utilized for event tree linking adequately account for accident sequence delineation and dependent effects of the important support systems.

3.3 System Modeling

A. Insights and Important Assumptions.

The STP PSA does not provide system failure models of graphic fault trees consisting of component failures combined by "and" and "or" gates. Because of the nature of the PLG techniques, the quantification of system failures can be developed without such a graph. Instead of graphic fault trees, block diagrams are used and Boolean equations for block diagram are developed. [Reference 1, Section 4.2.2.1.1]

The System Descriptions appended to the PSA adequately document system failure models at the component level.

3.4 Quantification

This section provides a short summary of the PLG PSA techniques for quantifying internally-initiated core melt sequences and a discussion of the quantification aspects of the STP PSA.

3.4.1 Techniques

A. Insights and Important Assumptions.

The quantification technique is discussed in sections 4 and Appendix A of the PSA. [1]

System level quantification is accomplished by convoluting Discrete Probability Distributions (DPD) for constituent components according to the failure or success logic created to model the system. Independent failures of identical components within a given system are correlated (DGs fail-to-start for example); there appears to be no correlation for identical component failure modes among components in different systems (e.g., MOVs fail-to-open). Common mode dependent failures are modeled using the Multiple Greek Letter (MGL) method. The DPD technique enables all types of probability distributions to be convoluted even if they are not well-behaved, lognormal in form.

The result of a system level quantification is a probability distribution for a split fraction of an event tree. As summarized in Section 3.2 of this report, event tree linking is used to assemble the appropriate split fraction models into an accident sequence. Intersystem dependencies are accounted for by development of system failure models for each specific split fraction as specified by each sequence of events in the large event trees. The quantification is rigorous in terms of probability distributions of constituent components. The resulting system or split fraction probability distributions are logical convolutions of all component probability distributions.

Accident sequences are initially quantified using point estimates (means) for each constituent split fraction. The PLG method tends to generate a large number of sequences, so the point estimate quantification is used to screen out nondominant sequences from further analysis. Important sequences are then subjected to a Monte Carlo uncertainty analysis by sampling the split fraction probability distributions to calculate sequence probability distributions. These probability distributions provide the final quantified results for the PSA. [4]

3.4.2 Data Base

A. Insights and Important Assumptions.

The PLG generic data base was the source of data for much of the STP PSA. [Reference 1, Section 7] This extensive data base provides probability distributions for numerous component-specific failures: hardware failures, common cause effects, and maintenance unavailability. No STP plant specific data was incorporated into the STP PSA data base for component related failures because the STP PSA data base was developed prior to plant operation. However, the generic data was screened for applicability to STP components.

The data base is comprised of both nuclear power plant experience and industry data compilations. Component specific failure quantifications are provided in Section 7 of the PSA.

For some of the failure rates contributing to the more probable core damage sequences at STP, Table 3.4.2-1 compares the mean values used in the STP PSA to the generic NUREG-1150 mean values. [4] Table 3.4.2.2 compares the STP mean Initiating Event frequencies to the NUREG-1150 values.

Table 3.4.2-1
Sample Mean Failure Rates

Component Failure Mode	Mean of STP Distribution	NUREG-1150 Value (Mean)
• Loss of off-site power	0.09/yr	0.11/yr*
• Diesel Generator, fail to start and run 24 hr (excluding test and maintenance)	0.10/demand	0.08/demand
• Turbine-Driven AFW Pump, fail to start and run 24 hr (excluding test and maintenance)	0.06/demand	0.04/demand

Generally, the data base for the STP PSA is extensive and the quantification methods are state of the art. Mean frequencies for a representative set of component failure modes from both the STP PSA and NUREG-1150 are shown on Table 3.4.2-3.

B. **Review Findings.**

Component specific data is provided in Section 7 of the PSA in tabular form; the mean, fifth percentile, median, and ninety fifth percentile points of the distribution for each specific failure are provided. These data tables do not provide units of the data, although the units can be deduced from the numerical values and from discussions accompanying the tables. In addition, there is no information on the specific distributions used to model the frequency distributions. It is not possible to reconstruct or understand the nature of the frequency distributions based on the limited information provided. For instance, Section 7 of the PSA contains several examples of deriving a distribution based on different types of data (e.g., generic data, operating experience). Some of the examples yield discrete distributions (see page 7.3-6 of Reference 1). Others yield continuous distributions which may be well defined, such as lognormal (Page 7.3-11), or numerically generated (Page 7.3-14). It is impossible to tell from the tables of the PSA data base which of these types of distribution is used for each frequency distribution. In item IE19 of Appendix 3, HLP stated that units in the tables are adequately given in descriptive material provided

*Sequoyah specific analysis. [Reference 14]

Table 3.4.2-2
Initiating Event Frequencies

Category	Initiator		Mean Frequency (Yr^{-1})	
	STP PSA	NUREG-1150	STP PSA	NUREG-1150
LOCA	Large LOCA	Large LOCA	2.0E-4	5.0E-4
	Medium LOCA	Intermediate LOCA	4.7E-4	1.0E-3
	Small LOCA-Nonisolable	Small LOCA	5.8E-3	1.0E-3
	Small LOCA-Isolable	Small Small LOCA	2.3E-2	2.0E-2
Transient	Reactor Trip	Transient with MFW Available	1.4E-0	6.6E+0
	Turbine Trip		1.1E-0	
	Loss of Primary Flow		1.8E-1	
	MSIV Closing		8.7E-2	
	Main Steam Relief/Safety Valve Opening		4.2E-3	
	Loss of Condenser Vacuum	Transient-Loss of MFWS	1.2E-1	1.7E-2
	Excessive Feedwater Flow		1.7E-1	
	Partial Loss of MFWS		1.1E-1	
	Total Loss of MFWS		1.6E-1	
	Inadvertent Safety Injection		3.0E-2	
	Main Steam Line Break		6.5E-3	
	Loss of Instrument Air		2.0E-3	
	Loss of Offsite Power	Loss of Offsite Power	1.3E-1	Plant Specific
	Transient Induced LOSP	--	2.7E-3	
	Loss of 125 Vdc Bus	Loss of 125 Vdc Bus	3.3E-3	5.0E-3
	Loss of ECW Systems	Loss of SWS	4.0E-4	Plant Specific
	Loss of CCW Systems	Loss of CCWS	1.8E-5	Plant Specific
	Loss of EAB HVAC	--	6.0E-5	--
	Loss of Control Room HVAC	--	1.8E-5	--
	Steam Generator Tube Rupture	Steam Generator Tube Rupture	2.8E-2	1.0E-2

Table 3.4.2-3
Component Failure Mode Frequency Estimates

Component Failure Mode	Mean Failure Frequency	
	STP PSA	NUREG-1150
Air Operated Valves		
Fail-to-Operate	1.5E-3	2.0E-3
Spurious Operation	2.7E-7/hr	1.0E-7/hr
Check Valves		
Fail-to-Open	2.7E-4	1.0E-4
Hydraulic Valve		
Fail-to-Operate	1.5E-3	2.0E-3
Motor Operated Valve		
Fail-to-Open	4.3E-3	3.0E-3
Fail-to-Remain-Open	9.3E-8/hr	1.0E-7/hr
PORVs		
Fail-to-Open-on-Demand	4.3E-3	2.0E-3
Fail-to-Reseat	2.5E-2	2.0E-3
Solenoid Valve		
Fail-to-Operate	2.4E-3	2.0E-3

Table 3.4.2-3
Component Failure Mode Frequency Estimates (Continued)

Component Failure Mode	Mean Failure Frequency	
	STP PSA	NUREG-1150
Motor Driven Pump		
Fail-to-Start	3.3E-3* 3.4E-3 2.4E-3	3.0E-3
Fail-to-Run	3.4E-5/hr	3.0E-5/hr
Turbine Driven AFWS Pump		
Fail-to-Start	3.3E-2	3.0E-2
Fail-to-Run	1.0E-3/hr	5.0E-3/hr
Heat Exchangers		
Rupture/Leakage	2.0E-6/hr	3.0E-6/hr
Diesel Generator		
Fail-to-Start-and-Run 1 hr	3.8E-2	3.0E-2
Fail-to-Run	2.5E-3/hr	2.0E-3/hr
Circuit Breaker		
Fail-to-Transfer	1.6E-3	3.0E-3
Spurious Transfer	8.3E-7/hr	1.0E-6/hr

*The STP PSA used slightly different estimates for pump failures in different systems.

Table 3.4.2-3
Component Failure Mode Frequency Estimates (Continued)

Component Failure Mode	Mean Failure Frequency: STP PSA	Mean Failure Frequency: NUREG-1150
125V DC Battery		
Fail-to-Deliver-Power During Operation	7.5E-7/hr	1.0E-6/hr
Charger Failure During Operation	1.9E-5/hr	1.0E-6/hr
Strainer		
Plug	6.2E-6/hr	3.0E-5/hr
HVAC Fans		
Fail-to-Start	4.8E-4	3.0E-4
Fail-to-Run	7.9E-6/hr	1.0E-5/hr
Air Compressor		
Fail-to-Start	3.3E-3	8.0E-2
Fail-to-Run	9.8E-5/hr	2.0E-4/hr

with the tables. Details on distributions are contained in reference 7-17 of the PSA which is proprietary information of PLG. The data base was made available for the review process.

3.4.3 Testing and Maintenance

A. Insights and Important Assumptions.

Testing and Maintenance unavailabilities are discussed in Section 7.5 of the PSA.(1) Constituent causes include: repairs during operation, repairs following scheduled testing, scheduled testing, unscheduled repairs and testing, and preventative maintenance. Probability distributions on both the frequency and duration are used to develop unavailability probability distributions for a specific component.

The PLG generic data base served as the source of data. Plant specific features and site specific maintenance policies and procedures were considered in applying the generic data for frequency of maintenance to specific components. No specific illustration is supplied in the PSA, but the application of the generic data base to plant specific features is discussed in Section 7.5 of the PSA. Plant specific technical specifications and component specific mechanical details were used to correctly apply the generic data for duration of maintenance to specific components.

The STP PSA considered asymmetries in train unavailabilities within a given system. This aspect was discussed in Section 2.3.1 of this report. Different maintenance-caused unavailabilities among trains within a given system can result due to the following reasons:

- A train may be operating, in auto standby, or in manual standby. (ECW for example.)

- One train may be comprised of different hardware than another. (AFW turbine driven, DC controlled train D for example, as contrasted with motor driven, AC controlled trains A, B, and C.)

- Technical specifications may allow different outage times among trains (AFW Train A can be inoperable longer than Trains B or C.)

The plant specific maintenance data for the STP PSA appears reasonable.

3.4.4 Common Cause

A. Insights and Important Assumptions.

Common cause failures are modeled in the PLG generic data base through the Multiple Greek Letters (MGL) method. This method can be used to quantify common cause failures among more than two identical components. The PLG generic data base was used as the basis for common cause parameter quantification.(16) Data from this data base was screened for applicability to STP. [Reference 1, Section 7.4.3].

The actual screening of the data and quantification of common cause probabilities are not explicitly documented. However, the consideration of common cause events in the STP PSA appears complete. Section 7.4 of the PSA discusses common cause failures. [1]

3.4.5 Human Factors

A. Insights and Important Assumptions.

The human error rates (HERs) used in the STP PSA were compared to values used for similar human errors by other PRA studies. The majority of the South Texas values were higher than those used by other studies. The remainder were within the same range of values. This somewhat tempers the concerns addressed in this section regarding the lack of documentation.

B. Review Findings.

The comments presented in this section follow Section 15 of the STP PSA, [1] i.e., the comments on Section 15.1 and 15.2 are ordered such that they follow the presentation of the methodology in Sections 15.1 and 15.2. A synopsis of the replies provided by the STP to these comments (as interpreted by the reviewer) as well as additional comments have been added in the appropriate places and labeled as such. The actual detailed replies can be found in Appendix 4.

The human actions analysis methodology is a combination of variations of three methodologies; SLIM, SHARP, and THERP. [17] How these methodologies are varied from their original derivation and why they have been changed is not documented. Also, as with many other HRA methodologies, SLIM has not been universally accepted by the HRA community.

<u>Synopsis of Plant Reply to Reviewer Questions and Comments</u>

The HLP reply stated that there is no current methodology that provides a precise, theoretically verifiable, numerical prediction for human actions (as modeled in PRA studies today) that HRA/PRA practitioners agree upon. This is certainly true. This reviewer's hesitation with the use of SLIM is its dependence on the calibration points. A conversation with plant personnel indicated that an attempt was made to minimize this dependency by using a wide variety of data from numerous other studies. This appears to be a reasonable approach to use given the time and economic constraints associated with a PRA.

A detailed THERP analysis was not performed. Tabulated values and dependency correlations from the THERP methodology were used as references for system-level human errors that may leave equipment disabled during normal plant operation. The system analysts identified those actions that were considered to be critical (i.e., actions that could leave a piece of equipment disabled and undetected) and then applied the tabulated error rates found in THERP. The principles of SHARP were used to guide the qualitative identification and representation of dynamic human errors in the event sequence diagrams and event trees. The modeling process combined some of the seven formal steps associated with the SHARP methodology and simplified others. Appendix 4 contains more explicit details on the adaptation of the seven steps for the STP PSA. Modifications made to the SLIM methodology are described in Appendix 4. The modifications included changing the format used to document the expert assessments, the use of a predefined set of seven performance-shaping factors, and the "inversion" of the process to calculate a "failure likelihood index". References for the three methodologies are also contained in Appendix 4.

<u>Section 15.1 and 15.2</u>

The goals listed for the human reliability analysis (see page 15.1-1, fourth paragraph) are important. One goal that has not been mentioned but is equally important, is the ability of an individual not involved in the original analysis to use the methodology presented to obtain duplicate Human Error Rate (HER) values. The methodology presented should enable the reader to reproduce the results.

The last paragraph of Section 15.1 states, "The methodology developed and used in evaluating the dynamic human actions in the event sequences and the recovery actions in this study is relatively new, it is believed to be a significant improvement over previous methodologies by providing a greater traceability to basic factors affecting human performance." The difference between the new methodology and that used previously is not clear. In Section 15.2, the first paragraph attempts to describe the new methodology, "PLG has adopted an application of SLIM to quantify the event-level dynamic operator actions in the plant response model of a PRA." No reference has been given for SLIM. There are several versions of SLIM available, the majority of which are the SLIM-MAUD version. Therefore the version referenced in this review for comparison purposes is, <u>The Use of Performance Shaping Factors And Quantified Expert Judgement in the Evaluation of Human Reliability: An Initial Appraisal</u>, by David E. Embrey. [18] Documentation of the differences between David Embrey's SLIM version and that chosen for the STP PSA along with justification for the changes would help validate the methodology by emphasizing any improvements made.

There are some problems associated with the PRA application of SLIM. The following statements are excerpted from various sections of GRS Project RS688 [19] which evaluated and compared various HRA methods. The following statements from Reference 19 highlight one HRA expert's opinion on why SLIM has limited use as an HRA procedure.

> SLIM uses individual judgements combined statistically, it requires structure and guidance for these judgments. Evidence on the consistency and validity of SLIM is unconvincing, more research is required. Direct outputs from SLIM are interval scale numbers called SLI numbers ranging from 0 to 100. The SLI numbers must be converted to estimated HEPs by means of calibration using HEPs from some objective source. Use of estimates obtained from some other psychological scaling technique should not be used to calibrate SLIM estimates. Calibration data can consist of in-plant HEPs or training simulator HEPs that are plant-specific. If simulator data

are used as calibrators, analysts need to recognize the problem of the validity of the simulator data themselves. Calibrators are required for each homogeneous subset of tasks. The flexibility of SLIM enables it to treat any aspect of human behavior. Keep in mind that the direct outputs of SLIM are interval scale values, and must be calibrated if they are to be converted to HEPs to be used in a PRA. SLIM stresses the importance of specifying relevant Performance Shaping Factors (PSFs) so that all judges have the same PSFs in mind when making judgments. Judges consider one PSF at a time and do not appear to be instructed on how to handle any interactions. There is no method for handling discrepant group opinions in the consensus mode. Another objection to the methodology is the assumption that the likelihood of error in a particular situation depends on the combined effects of a small set of PSFs.

Section 15.2 of the PSA, page 15.2-1, states, "Seven PSFs have been selected to span the range of problems that operators face". A Performance Shaping Factor is any factor that influences human behavior. PSFs may be external to the operator or may be a part of his or her internal characteristics. As can be seen from its description, PSFs can be chosen from a wide variety of factors. The STP PSA does not document how their PSFs were narrowed down to seven or why these are the most important. Following are some quotations on PSFs from the Embrey report: [18]

> ...a team of expert judges decides on a set of PSF which are deemed to be the major determinant of reliability in the broad category of tasks being considered.
>
> ...The composition of the panel of judges could include operators, supervisors, human factors specialists, and other experts with insight into the factors which could impact reliability. The derivation of the initial PSF set will involve direct interaction between subject matter experts in order to arrive at a consensus for the task categories concerned.
>
> ...If a group of judges is asked to derive a global set of PSFs for a task category, it is possible that they may have differing mental models of the ways in which the PSF should be weighted or can combine, to produce the resulting probability of task success. The imposition of the simple reliability model on the experts judgement is a means of increasing the homogeneity of their perceptions of the situation, thereby assisting in reaching a consensus.

For the STP PSA, it was not clear whether a team of expert judges was used to decide on the PSFs, and if so, who they were and what their credentials are. Also, the reliability model was not adequately described.

The PSA describes an operator response form developed to document the factors affecting operator performance. Is Table 15.2-1, the scenario sheet form, the operator response form? If the scenario sheet form is the operator response form, it doesn't appear to provide a "qualitative assessment of the problems that the operator will face while undertaking an action" as described in the documentation. If these forms are not equivalent, where is the operator response form and what is the scenario sheet form?

The third paragraph of Section 15.2 states, "The quantitative evaluation of the HER is accomplished by assessment teams of operators and PRA team members...". Who were the people used as the expert judges? Did the mix of individuals used as judges provide varying sources of information? What training was provided to these experts? The following statements are some excerpts from the Embrey 1983 report [18] regarding expert judges:

> Multiple experts with varying sources of information are the most effective estimators of likelihoods as long as they are all reasonably knowledgeable regarding the area being considered.
>
> Training in probabilistic thinking can improve the judges' estimates. Training should also acquaint the judges with known biases which can affect judgments.

Is the weight of each PSF, w_i, the normalized weight? The derivation of the Success Likelihood Index (SLI) or Failure Likelihood Index (FLI) by Embrey normalizes the weight for each PSF. After reading through the rest of the Section 15 documentation it does appear that the normalized weight is used.

The calibration tasks are selected from HERs determined by PRAs of other nuclear power plants. As stated previously, use of estimates obtained from some other psychological scaling technique should not be used to calibrate SLIM estimates.

The STP PSA adaptation of SLIM resulted in a series of steps. The first step refers to the methodology outlined in Steps 1 and 2 of SHARP. There is no reference given for SHARP. Therefore the assumed version used is EPRI NP-5546. [23] Step 1 also mentions a split fraction failure criteria but doesn't define the term.

Step 4 refers to the methodology outlined in Step 3 of SHARP and to Table 15.2-1 (the scenario sheet form). It is implied that use of the scenario sheet form implements the Step 3 SHARP methodology, but the scenario form doesn't document the operating experience (e.g., plant-specific event write-ups, LERs and events from other plants) that were scrutinized for the tasks to identify mishaps and corrective actions taken. Furthermore, it does not document the influence parameters (e.g., method of detection, alarms available, coordination required). This is a large deviation from step 3 of SHARP. Was the intent to detail the task without including the influence parameters? A thermal hydraulic analysis is mentioned but no further information is given. A brief overview of what was done would be helpful.

Each of the seven PSFs have a descriptive scaling guide (see Table 15.2-2) that provides a method of achieving consistency when using several expert judges. The scaling guides look reasonable but there is no discussion of the methodology and individuals used to develop it.

Step 8 mentions a LOTUS 1-2-3 program that was developed to aid in the classification of operator actions in groups having similar PSF weights. No discussion of the methodology used for the program was provided.

None of the steps addressed what would happen if no consensus could be reached for the final rating of the group?

Synopsis of Plant Reply to Reviewer Questions and Comments

It was agreed that more information on the process used to produce the HRA values (i.e., the methodology) was necessary. Further documentation was provided and conversations with the plant and with John Stetkar, of PLG, were conducted. While the questions asked by this reviewer were adequately answered, it was suggested that a methodology document that follows the PLG approach would aid other analysts in interpreting the procedure with substantially more ease. Without access to individuals familiar with the process, it would be extremely difficult to obtain the same results.

The STP PSA used a PLG adaptation of SLIM. Three significant improvements were stated as being achieved by use of this adaptation. The first advantage was a technique for documenting, in detail, operator input. The operators are given the opportunity to assess the human response that would occur during a particular scenario. The second advantage involved the quantification of uncertainties. It was felt that with the number of groups evaluating the scenarios, a variety of opinions are considered. This leads to a large range of uncertainty if the opinions differ greatly and a narrow range of uncertainty if the groups are in close agreement. Finally, this adaptation provides a method to identify areas that need improvement (e.g., the procedures for a certain scenario may be poor, plant indications may be difficult for an operator to use for a particular series of events, inadequate training may be provided for a particular scenario, etc.). It is also felt that proposed plant improvements can be evaluated by use of this method.

Seven PSFs were used in the STP PSA. These seven were chosen after a number of trials performed over several PRAs by PLG and were felt to be the best combination of four attributes; completeness, independence, representative of important influences, and evaluation efficiency. PLG has attempted to use up to 22 PSFs which has resulted in poor results due to overwhelming the evaluators with the process. This leads to a diminishment in the care and quality of the assessments done. Another problem observed when a large number of PSFs are used is the difficulty the experts have in expressing extremes in their opinions. It is not known why this occurs but it is an observable phenomena.

The operator response form described in Section 15.2 is the scenario sheet form (Table 15.2-1 is a blank version of the form). The purpose of this form is to provide a description of the scenario that is going to be evaluated. Enough information is provided to develop an understanding of what is happening in the plant but not so much information that a bias is introduced.

The groups chosen as the experts were the combinations of individuals that would be in the control room together during an accident scenario. Each group was briefed and was encouraged to reach a consensus, as this would be the case during an actual event. However, "irreconcilable" differences were also noted and accounted for by using uncertainty bounds representative of the range of opinions.

As stated previously, the use of estimates obtained from other psychological scaling techniques are not recommended for use as the calibration points, as this tends to bias the human error rates toward the calibration point values. However, the STP attempted to minimize this effect by using a large data base that contained a variety of HRA estimates. Given the fact that plant-specific and simulator data are scarce, the approach used seems reasonable.

The STP version of SLIM has as its first step a variation of steps one and two of SHARP. The first step of SHARP was used to identify the important human actions that may affect event sequence progression, core damage, or plant damage states. The second step of SHARP was not used in a quantitative way but rather as a technique to use in order to make qualitative decisions about each prospective human action in the event model.

A split fraction is the value assigned to a top event at a particular location in the event tree structure. Appendix 4 contains an example that clarifies what is meant by a split fraction failure criteria.

Step four of the STP version of SLIM is an adaptation of step three of SHARP. The fundamental elements of the SHARP step were implemented during the translation from the somewhat generally defined operator actions in the event sequence diagrams to the explicitly defined top events and split fractions in the event tree models. Important physical, functional, and cognitive dependencies are identified during this step of the process, and separate top events or split fractions are defined to coherently represent these dependencies within the resulting event sequences. The scenario description forms then document the event progression, required actions, and the major factors that influence operator response for each split fraction.

Additional information on the thermal hydraulic analysis that was used is provided in Appendix 4. The thermal hydraulic analysis used information from preceding system successes and failures to determine operator response times.

The descriptive scaling guide was used to provide an initially consistent frame of reference for the PSF ratings assigned by the experts. The history of its development and current use is presented in Appendix 4. Generally, the guides have evolved through implementation at various plants and are used to assign numerical values to physical situations.

A LOTUS 1-2-3 program was used for two principle functions during the quantification. The first function was a simple spreadsheet sort and merge to allow the analyst to group similar PSF weights. The second was a numerical analysis that calculates the FLI for each action, determines the best-fit curve for the calibration points and stores the point-estimate HER to be used in the analysis.

Section 15.3

The expected omission error rates and commission error rates (see Tables 15.3-1 and 15.3-2 respectively) are presented with no indication of where the rates originate or why these particular values are appropriate.

Justification is not given for the use of Figure 15.3-1 to determine the calibration error. The Seabrook PSA [12] was given as the source of the figure, but more specifics on its location in the document would be helpful.

A RISKMAN designator is mentioned on page 15.3-2 but no definition of this term has appeared in Section 15.

A future consideration for the human error designators used in Table 15.3-4 is to use designators that yield a description of the human error being modeled. The description of Table 15.3-4 on page 15.3-2, "...and then the applicable situation from Table 15.3-3" leads to the column labeled, "Applicable Situation from Table 15-6", on page 15.3-6. Should these both indicate Table 15.3-2? It is not immediately obvious where the cumulative HER mean values on Table 15.3-4 originate. After some trial and error it was determined that they are an addition of the applicable situations from Tables 15.3-1 and 15.3-2. Better documentation would eliminate the trial and error process. The designator, ZHE01B, has two cumulative HER mean values associated with it, 6.1E-3 and 9.4E-3. Is this intentional? The human error rates listed on Table 15.3-4 were compared to the values used for similar human errors from the Grand Gulf and Peach Bottom NUREG-1150 analysis. [20.21] The majority of the South Texas values were higher, while the remainder were similar to those used in NUREG-1150.

Synopsis of Plant Reply to Reviewer Questions and Comments

The expected omission error rates (Table 15.3-1) are based on Table 15-3 in NUREG/CR-1278 by A. D. Swain and H. E. Guttmann. [17] The commission error rates (Table 15.3-2) are based on Table 14-1 and are also found in NUREG/CR-1278.

Figure 15.3-1 and Table 15.3-3, the miscalibration HER distribution, are taken from the Seabrook PSA, [12] Appendix D, Section D.6.3.2.2.2 and related Section 6.5. The South Texas instrumentation systems are similar to those of Seabrook. Therefore, the Seabrook results for miscalibration errors were applied to South Texas. This produces a conservative result (see Appendix 4).

RISKMAN is PLG proprietary software used in the analysis of data, system models, and event trees. The RISKMAN designator is simply a name attached to an event that allows tracking of the event through the analysis.

The description of Table 15.3-4 on page 15.3-2, "...and then the applicable situation from Table 15.3-3" should instead lead to Table 15.3-2. Table 15.3-4, the third column, should say from Table 15.3-2 instead of from Table 15-6.

A typographical error occurred on Table 15.3-4. The designator, ZHE01B, "on completion of ECW test, operator turns wrong valve instead of turning ECW return valve to full open position," should be ZHE01A. The second occurrence of the ZHE01B designator is correct.

Section 15.4

Section 15.4 begins with a description of what was done by the analysts from steps 4 through 11 in the methodology section (15.2). This brings up:

(1) What was done for step 1? What were some of the functions humans perform at each branch point in the preconstructed event tree? What classification system was chosen to ensure that significant human interactions are identified? What completeness checks were done?

(2) What was done for step 2? What screening technique was used to rank and select key interactions for detailed analysis? What were the results? What was the cut-off parameter? Were selected operator actions observed in the plant environment?

(3) What was done for step 3? The PSFs described in Section 15.2 are not presented as the final set of PSFs. But, Section 15.4 doesn't indicate anything else.

The comments on Section 15.1 and 15.2 on the scenario sheets, are applicable for this section also.

Section 15.4, page 15.4-1, third paragraph states, "...five full operating crews evaluated the dynamic human actions following a briefing on methodology." The PSA does not expand on this, and it is not possible to ascertain whether the briefing incorporated probabilistic training and debiasing as recommended by Embrey [18].

The third paragraph of Section 15.4 mentions use of the letters H, M and L to provide input for the PSF weighting factor. But no discussion on what determines an H, M or L evaluation for PSFs is given. These evaluations don't appear to follow Embrey's SLIM methodology. Also, what was given to the eight evaluation teams (i.e., what documents, instruction) to aid them in their evaluations?

The HL&P training staff evaluation (Table 15.4-32) and the single shift supervisor evaluation (Table 15.4-33) contain all 43 actions. Some comment on this would be helpful.

The human action identifiers, HEOL02 and HEOL01, on Table 15.4-39 were labeled HEOL2 and HEOL1 on all of the other tables.

The fourth paragraph on page 15.4-1 of the PSA states,"Weighting factors of 10, 5, and 0 were assigned to PSF weights with letters H, M, and L, respectively. Then, these weighting factors were normalized to sum to one for each evaluated human action. Finally, these normalized PSF weights were averaged over all eight evaluations of the human actions." Use of this method yields a PSF weight averaged across all eight teams for each of the seven PSFs. The human actions are then grouped according to similar PSF weights over all seven PSFs. Three events were chosen to follow this methodology; HEOCH01, HEOB06 and HEOS02. (Our copy of the report is missing page 15.4-73, which restricts the number of PSFs available for review.)

Following the methodology description, the first step is to normalize the weighting factors to sum to one for each evaluation, then average these over all eight evaluations. The PSFs checked were task complexity and stress, respectively. These are documented on Table 3.5.4-1.

Table 3.5.4-1 Task Complexity and Stress PSF Weights

Evaluation Teams	HEOCH01		HEOB06		HEOS02	
	Normalized PSF for:		Normalized PSF for:		Normalized PSF for:	
	Task Complexity	Stress	Task Complexity	Stress	Task Complexity	Stress
Team 1	5/45	5/45	5/45	5/45	5/45	5/45
Team 2	5/35	5/35	10/70	10/70	5/35	5/35
Team 3	5/35	0	5/55	10/55	10/55	0
Team 4	10/30	0	5/30	5/30	0	0
Team 5	0	0	0	10/35	10/20	0
Team 6	5/30	5/30	5/50	10/50	10/45	5/45
Team 7	0	0	10/40	0	0	0
Team 8	0	5/30	0	10/40	5/25	5/25
Average over all 8 evaluation teams:	.1121	.0734	.0764	.1985	.1698	.0706
STP results (from Table 15.4-39):	.12	.08	.09	.19	.17	.07

As can be seen, the values derived here do not exactly match the numbers from the STP PSA. Perhaps the methodology has been misinterpreted, but independent checks by several analysts came to the same conclusion.

Tables 15.4-34 through 15.4-38 are the five operating crew performance-shaping factor evaluation sheets. The documentation states, "Members of each operating crew worked together to develop one evaluation sheet/crew." How were disagreements handled?

More information is necessary on how the 30 dynamic human actions are classified into six groups, this is difficult to duplicate without a copy of the LOTUS 1-2-3 program used to do this task. A more detailed description than that provided or an example would help.

Use of SLIM requires that the SLI (or FLI) numbers be converted to estimated HEPs by means of calibration from some objective source (e.g., in-plant HEPs or training simulator HEPs that are plant-specific). As mentioned previously, the calibration task data source used by STP was other PRA studies. An impressive amount of effort went into the collection of the data. However, there is some concern with using data from other PRA studies as the calibration points. One study, the European Benchmark Exercise On Human Reliability Analysis, [22] reports:

> "...SLIM results were shown to be extremely (too?) dependent on data used as reference points for calibration. When no good reference data are available, application of SLIM is not indicated. The results of the test and maintenance case show that there is a good agreement between the estimates obtained by a same team (sic) using THERP and SLIM. However, it is our belief that the sensitivity of SLIM to the anchor point probabilities and the fact that those probabilities were, either explicitly or implicitly, taken from the THERP data base, create strong dependency between the SLIM and THERP results." The operational transient study case states, "Considering the results within a same team (sic), the SLIM results always agree quite well with the results obtained by other methods, but this could be due to the calibration anchor points used. As already pointed out during the discussion of the test and maintenance results, this calibration has a large impact on the values obtained."

The calibration data chosen for each group of operator actions have PSFs associated with them, see Tables 15.4-47 through 15.4-52. How were these determined? It would appear that some judgement or interpretation is required by the analysts to get these.

The dynamic actions human error rates, Table 15.4-23, are reasonable. The values are consistent with those used in other PRA studies.

Section 15.2, the methodology, needs to tie into Section 15.4, the practice, more explicitly. It's not always clear how the two sections relate.

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The STP model, including all of the dynamic human actions, were based on the event sequence diagrams and event trees in Section 5 of the STP PSA report. These models were reviewed in detail by four separate groups in order to identify and confirm the human actions.

No screening values were used to rank the dynamic human actions. The detailed reviews of the sequence diagrams and event trees also involved classifying the human actions into two categories for quantitative analysis. The first category consisted of those actions judged to be important for the Level 1 core damage results, the level 2 interfacing plant damage states, or for general understanding of the event sequence progression. The events in this category were quantified using the methodology described in Section 15 of the STP report. The second category assigned screening values of 1.0 to the remaining events. This was done to avoid optimistic estimates for combinations of HER values that occur within a cut set.

The PSFs described in Section 15.2 are the final set.

Prior to each evaluation session the teams were provided with the scenario sheets (Tables 15.4-1 through 15.4-30) and the event sequence diagrams. A full set of plant drawings, all procedures, and the emergency response guideline background documents were available. One to two hours of training were given to the teams on the HRA evaluation methodology and probabilistic analysis. No formal debiasing training was performed. However, the results were checked for possible biases. One member of the HRA team monitored each evaluation session.

The PSF weights have been designated H (extremely important), M (average importance), and L (not important). Experience has shown that using these simple qualitative values increases the effectiveness of the evaluations. The PSF weights are assigned using group consensus opinion.

The HL&P training staff evaluation (Table 15.4-32) and the single shift supervisor evaluation (Table 15.4-33) were performed early in the analysis and thus contain all 43 of the human actions. This was done in order to orient senior training and operations personnel to the evaluation process and to get feedback on the scenario descriptions and information content, and to anticipate problems that could develop when the control room crews began their analysis. As a result, some human actions were eliminated and others were combined. Thus, a final set of actions was established for the control room crews to evaluate.

The methodology used to determine the PSF weight had an additional step which was not originally documented. It involved a finer definition than that provided by the H, M, L designators. The evaluation teams added a + or - to the designators. This change resulted in slightly different values than those obtained using the 10, 5, and 0 valves associated with H, M, and L designators.

The LOTUS 1-2-3 program uses a simple spreadsheet sort and merge to allow the analyst to group similar PSF weights.

The calibration data chosen for each group of operator actions have been assigned PSFs by the HRA team. Optimally, this would have been done by the evaluation teams but, due to time constraints, this wasn't a possibility.

Section 15.5

Since the evaluation of the recovery actions follows the methodology presented in Section 15.2 (as does Section 15.4), the comments made on Section 15.4 apply for Section 15.5 as well.

The tables of recovery actions, Tables 15.5-19 and 15.5-20, for some recovery actions and some PSFs, have normalized the weighting factors. Is there any particular reason that some are normalized and some aren't? What is meant in the remarks column by the H:2.2-2, M:4.0-3, L:1.6-3, etc.?

The recovery actions human error rates, Table 15.5-37, look reasonable. The values are consistent with those used in other PRA studies.

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All numerical values on Tables 15.5-19 and 15.5-20 associated with the H, M, and L designators should be ignored.

Section 15.6

Overall the description of the methodology used for electric power recovery actions was good. There were a few items that were not clear which will be discussed in the following paragraphs.

There was no reference for the STADIC computer code. A better description of the code is required before an understanding of what the code does is possible.

QDG is a subroutine of what program? It is assumed the STADIC code but it's not stated in the document.

It's not clear how boundary conditions for a specific event scenario define the power failure function or how the nature and timing of the failures determine the recovery distribution. An example would help clarify what was done.

The tables presented on pages 15.6-7, 15.6-8, 15.6-9 and 15.6-16 have values that can be associated with several other values. For example, the table on page 15.6-8 has a 0.5 value for time following operator response that corresponds to a probability of 0.20 and 0.10. Which value is used?

Justification for the probability values used on the table presented on page 15.6-9 would be helpful.

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A MAPP analysis is mentioned on page 15.6-13 but no reference or information about it is provided.

STATIC is a PLG proprietary computer code that is used for Monte Carlo sampling and for calculations associated with probability distributions. Probability distributions are input into the code. Equations that describe the desired combinations of these distributions are input as FORTRAN subroutines. QDC is a subroutine of the STATIC code used to calculate the unavailability of the diesel generators as a function of their operating time after a loss of offsite power has occurred.

The boundary conditions for a specific event scenario determine the expected plant response and the time available for AC power recovery. As an example consider the situation where offsite power is lost and all three diesel generators fail to start. The recovery time will vary depending on the status of the turbine-driven auxiliary feedwater pump and the positive displacement charging pump. The amount of time available to restore AC power may be limited by the time available for steam generator dryout, reactor coolant pump seal failure, or station battery depletion, depending upon the availability of steam generator makeup flow and reactor coolant pump seal injection flow.

The probability values used on the table presented on page 15.6-9 were developed by the PSA team after discussions with the plant operations personnel, review of the emergency operating procedures, evaluation of typical and minimum required staffing per shift, and walkdowns of the plant.

No MAPP analysis were performed.

3.5 Binning of Core Melt Sequences

A. Insights and Important Assumptions.

To simplify the PSA, various pinch points are utilized. [Reference 1, Section 4.1.3.2.2.] A pinch point is a stage of the analysis for which the subsequent modeling is independent of how the stage was achieved. Every accident sequence that results in core melt can be categorized by the timing of the melt, the thermodynamic state of the primary system at the point of melt, and the status of plant systems when the melt occurs. Thus, core melt is a pinch point in the analysis. Although the current STP PSA does not evaluate source terms, it is necessary to consider the state of containment in a Level I PSA so that dependence among core cooling and containment is adequately considered. Thus, the state of containment and its associated protection systems such as isolation, heat removal, and fission product scrubbing, are appropriate to include in the categorization of core melt accident sequences.

The STP PSA bins core melt sequences into four Plant Damage States (PDSs). [Reference 1, Figure 4.1-6, Figure 5.1-1 and Table 16.1-6.] The four PDSs are:

- PDS Group I: core melt with intact containment.

- PDS Group II: core melt with late containment failure.

- PDS Group III: core melt with small early release.

- PDS Group IV: core melt with large early release.

The PSA discusses the binning of the dominant sequences in Section 16.

B. Review Findings.

Although it is not required to rigorously justify the containment response model in a Level I PRA, numerous aspects of the STP PSA containment response model should be justified by the Level II PSA, or its equivalent. These aspects are discussed in Section 2.1.8, Containment Cooling, of this report and they are, in summary:

- The impact of no spray injection on containment integrity.

- The minimum complement of containment cooling components required for long term heat removal. Equipment operability under these conditions.

- The justification for three-inch equivalent diameter containment bypass as a criterion for containment pressurization.

- The assumption of core melt prior to containment failure given no heat removal.

- The possibility for early containment failure due to means other than failure to isolate, such as steam explosion and direct containment heating.

3.6 Dominant Sequences

Section 2 of the STP PSA provides results of the Level I PSA for internal events. [Reference 1] The conclusion of the analysis is that the mean frequency of core melt is 1.7×10^{-4} per reactor per year, and is dominated by internal initiating events. The dominant sequence has a mean frequency of 1.2×10^{-5} and twenty other sequences have a mean frequency greater than 10^{-6}. These twenty one sequences constitute about 34% of the total core melt frequency; the remaining 66% is due to many sequences, each of low frequency.

Table 2.1-3 of the PSA summarizes the top twenty one sequences. This table alone does not provide sufficient detail to evaluate the sequences in terms of constituent event tree split fractions. An additional table, "Analysis of Additional Top-Ranking Sequences to Mean Core Damage", was provided which enables each sequence to be examined in terms of contributing split fractions. This information is reproduced here as Table 3.6-1, which is included as Appendix 2 to this report. Using this table it is possible to refer to the appropriate split fractions in the System Description notebooks of the PSA and identify dominant component-specific failures contributing to the sequence of interest. The remainder of this section is based on a detailed review of this table; reference to sequence number is consistent with this table in which the sequences are ordered in terms of decreasing frequency. Section 2.2 of the PSA summarizes the importance of various initiating events and mitigating system failures. The following conclusions were determined by review of Table A2-1 along with the System Descriptions. The conclusions agree with the results of Section 2.2 of the PSA.

A. Insights and Important Assumptions.

The twenty one dominant sequences may be categorized by initiating event as follows:

- Eight are station blackout sequences initiated by loss of offsite power; Sequences 1, 2, 5, 6, 11, 12, 13, and 15.

- Five are initiated by loss of offsite power followed by loss of main feedwater; Sequences 10, 14, 17, 18, and 19.

- Two are initiated by normal reactor trip; Sequences 7 and 21.

- Two are initiated by a steam generator tube rupture; Sequences 16 and 20.

- Two are initiated by loss of EAB HVAC which leads to station blackout; Sequences 3 and 4.

- One is initiated by loss of main feedwater, Sequence 8.

- One is initiated by normal turbine trip, Sequence 9.

Station blackout is involved in ten of these twenty one sequences, eight of which are initiated by loss of offsite power and two of which are initiated by loss of cooling for electrical switchgear. Four of the twenty one sequences are initiated by anticipated transients; namely, reactor trip, turbine trip, and loss of main feedwater. Two of the twenty one sequences are cause by a steam generator tube rupture.

The importance of mitigating system failure, excluding recovery, in the twenty one dominant sequences can be summarized as follows:

- Failure of one, two, or three Diesel Generators (DG) occurs in twelve sequences. Failure of three DGs occurs in sequence 1 and 12. Failure of two DGs occurs in seven sequences; Sequences 2, 5, 10, 11, 14, 15, and 18. Failure of one DG occurs in three sequences; Sequences 6, 13, and 17.

- Failure of turbine driven AFW train D occurs in eleven sequences; Sequences 1, 2, 3, 10, 11, 13, 14, 17, 18, 19, and 21.

- Failure of required operator action occurs in five sequences; Sequences 7, 8, 9, 16, and 20.

- Loss of RCP seal cooling occurs in four sequences; Sequences 4, 5, 6, and 12.

- Failure of motor driven AFW trains occurs in six sequences; Sequences 10, 14, 17, 18, 19, and 21.

- Loss of ECW train B occurs in six sequences; Sequences 2, 6, 13, 15, 17, and 19.

- Loss of EAB HVAC train C occurs in four sequences; Sequences 5, 6, 11, and 13.

- Small LOCA due to a stuck open PORV contributes to one sequence; Sequence 15.

None of the twenty one dominant sequences are initiated by a LOCA. There are no dominant sequences involving LOCA initiators followed by loss of recirculation cooling (commonly labeled as AH, S_1H, and S_2H sequences from the NRC event tree method). Such sequences were dominant in some of the NUREG-1150 PWR studies. Dominant contributors to such sequences include failure to switch over from injection cooling to recirculation cooling, and loss of ECCS pump and room cooling. Since the STP ECCS pumps are self-cooled, draw suction directly from the sump, and the PSA assumes no forced cooling is required for the ECCS pump rooms, failure of the ECCS systems to mitigate a LOCA is of low probability. Also, switchover of ECCS to recirculation is automatic at STP. As pointed out in Section 2.2.3 of this report the PSA does not fully justify the assumption that ECCS pump room cooling is not required. Transient induced LOCAs occur in five of the twenty one dominant sequences; Sequences 4,5,6,12 and 15. In each of these sequences, station blackout is involved and hence no ECCS is available due to lack of electrical motive power for injection pumps.

Station blackout by itself does not lead directly to an RCP seal failure. The PDP charging pump can be powered by the TSC diesel generator and seal failure occurs only if this capability is also lost. Four station blackout sequences involve loss of RCP seal cooling from the PDP; numbers 4,5,6, and 12. As discussed in Section 2.2.3 of this report, the PSA should reference the calculation supporting the assumption that PDP room cooling is not required.

The STP plant has one turbine driven AFW train, Train D. Of the ten dominant sequences involving station blackout, five involve loss of AFW train, D; numbers 1,2,3,11 and 13.

Loss of ECW train B contributes to six dominant sequences, while loss of Train A or B contributes to none of the twenty one dominant sequences.

This is reasonable based on the assumption that ECW Train ‸ is not as available as train A or C as discussed in Section 2.3.1 of this report.

Loss of EAB HVAC train C contributes to mitigating system failures in two of the dominant sequences, while loss of Train A or B contributes to mitigating system failures in none of the twenty one dominant sequences. This is reasonable based on the assumption that EAB HVAC train C is not as available as Train A or B as discussed in Section 2.3.1 of this report.

Both of the SGTR initiated dominant sequences involve operator failures to establish RHR cooling and hence negate the driving pressure for the loss of coolant through an unisolated, ruptured steam generator. Operator actions also contribute to mitigating system failures following three dominant sequences initiated by anticipated transients (reactor trip, turbine trip, and loss of main feedwater).

The System Descriptions included as part of the PSA can be used to identify specific mitigating system component related failures of significance to the twenty one dominant sequences. This can be done by identifying component failures contributing most to the split fractions within each dominant sequence. The following component-specific failures are important:

- Diesel generator failures are dominated by independent hardware failures of the required number of diesel generators to run for 24 hours, the mission time.

- AFW train D failures are dominated by failure of the turbine driven AFW pump to start and run for 24 hours.

- ECW train B failures are dominated by preventative maintenance.

- EAB HVAC train C failures are dominated by maintenance.

- Loss of PDP cooling to RCP seals is dominated by hardware and maintenance failures.

B. Review Findings.

The table of the twenty-one dominant accident sequences, (Appendix 2) was not incorporated into the PSA itself. The tabular summary of dominant sequences in the PSA did not provide the information needed to determine exactly which split fractions constitute each dominant sequence. This comment is offered as a suggestion for displaying results, and not as pointing out a deficiency of the PSA.

C. Potential Problems Resolved.

The table of dominant accident sequences appears to disagree with the System Description split fraction quantification [1] for sequences involving failure of motor driven auxiliary feedwater trains:

- For Sequences 10 and 17 in Table A2-1, the failure of AFW train D and train C is attributed to split fraction AFP, yet System Description 9 (AFW) identifies AFP as the failure of AFW Train D and Train A.

- For Sequence 14, the failure of AFW train D and Train B is attributed to split fraction AFP.

- For Sequence 18, the failure of AFW Train D (turbine driven) and Train A is attributed to split fraction AFQ; yet the System Description 9 identifies AFQ as the failure of two motor driven trains.

- For Sequence 19, the failure of AFW Train D and Train C is attached to split fraction AFO, yet the System Description 9 identifies AFO as the failure of two motor driven and one turbine driven AFW trains.

The System Description split fractions indicate that AFW train A failures are more likely than Train B or C failures as expected based on the discussion in Section 2.3.1 of this report. This trend is not consistent with Table A2-1.

Further confusion arises from conflicting descriptions of the same top event between Table A2-1 and Section 2.2 of the PSA. For example, in Sequence 1 of Table A2-1, top event (or split fraction) G3 is described as loss of "All Three Diesel Generators Supplying Safety Related 4160V Buses." In Table 2.2-2 of the PSA, it is also described as loss of all three DGs. However, in Table 2.2-3 of the PSA, G3 is described as "Failure of Diesel Generator 13 Given that Diesel Generators 11 and 12 Have Failed." Such inconsistencies make it very difficult to understand the sequence models.

In item PP3 of Appendix 3, HLP resolved the confusion over the split fractions for AFW as follows:

- For Sequences 10 and 17 the failure of AFW trains C and D is conservatively modeled as the failure of trains A and D. (Train A has a higher unavailability than train C.)

- For Sequence 14, the failure of AFW trains B and D is conservatively modeled as the failure of trains A and D. (Train A has a higher unavailability than train B.)

- For Sequence 18, the correct split fraction is AFP. This correction increases the frequency of Sequence 18 from 1.4×10^{-6}/yr to 2.7×10^{-6}/yr, but has negligible change on overall core damage frequency.

- For Sequence 19, split fraction AFO is correct but the event description for AFO is incorrect. AFO is the failure of two motor driven and one turbine driven AFW trains.

These corrections will be made in the next update of the PSA.

4.0 DOCUMENTATION

This section summarizes the adequacy of the documentation provided in the PSA [1].

4.1 Methodology

B. Review Findings.

The PLG methodology is described in the STP PSA, but its application to STP is not always clearly explained. Several major components of the methodology, such as HRA, uncertainty analysis, and split fraction definition and quantification, had to be explained and illustrated in detailed presentations by HLP and PLG personnel to the reviewers. A simple, complete example application of the methodology would assist in understanding the nuances of the techniques.

4.2 Plant Model

A. Insights and Important Assumptions.

The behavior of plant systems is well documented in the PSA [1]. The format of the System Descriptions is well suited for updating the PSA as plant modifications are performed.

B. Review Findings.

The System Descriptions do not include simplified drawings or fault tree graphs consisting of "and" and "or" gates. This is a disadvantage for the reviewer of the PSA, but it does provide an important advantage for on-site application of the PSA. If analysts use controlled plant drawings (P&IDs, wiring diagrams, electrical one line and metering drawings, etc.) they are more likely to correctly evaluate the system-specific implications of complex design modifications.

4.3 PSA Applications and Results

A. Insights and Important Assumptions.

Overall, the PSA techniques as put forth by PLG were applied in a consistent and accurate fashion.

B. Review Findings.

Documentation of the dominant sequences does not indicate which split fractions contribute to each sequence. Table 2.1-3 of the PSA does not provide this information. Table A2-1 of this report does identify sequence specific split fractions but it is not included in the PSA. In item IE21 of Appendix 3, HLP argues in item IE21 of Appendix 3 that the PSA is sufficiently well documented without the inclusion of Table 3.6-1. However, information on the dominant sequences displayed in a format such as Table 3.6-1 would improve the presentation of results in the PSA.

5.0 SPECIAL TOPICS

This section discusses the results of the STP PSA in the context of the plant design.

5.1 Discussion of Value for Internal Events Core Melt Frequency

The mean value for core melt frequency at STP is 1.7×10^{-4} per reactor year from internal initiating events. This value is larger than one might expect given that STP has three ECCS trains and four AFW trains. Mean core melt frequencies from internal initiators at other plants have been calculated as: [4]

- 4.1×10^{-5} for Surry
- 4.5×10^{-6} for Peach Bottom
- 5.7×10^{-5} for Sequoyah
- 4.0×10^{-6} for Grand Gulf
- 3.4×10^{-4} for Zion

Although direct comparisons of means are not valid for determining sweeping conclusions; they are useful for evaluating trends.

Four possible reasons for the higher mean frequency at STP are:

- Conservative quantification of loss of offsite power recovery.
- Only one turbine driven AFW train.
- The separation between the two units.
- Plant specific assignment of Human Error Rates.

All four of these possibilities are discussed in this section.

The STP PSA allowed only one hour to restore offsite power, yet the mission time of these sequences is 24 hours. Furthermore, the value for failing to restore offsite power within one hour is 0.47, versus NUREG-1150 values of 0.44 for Surry, 0.19 for Sequoyah, 0.19 for Grand Gulf, and 0.11 for Peach Bottom. The value used for the STP PSA may be accurate for the regional grid at STP, but the recovery model used to quantify LOSP sequences (only hour for recovery of any power related fault) causes the STP PSA results to be very dependent on the one-hour recovery event. NUREG-1150 LOSP recovery failures drop to 1.0E-2 after approximately 10 hours.

In item IE22 of Appendix 3, HLP stated that DG failures and recovery of offsite power were appropriately convoluted over the 24 hour mission time and this approach is summarized in section 15.6.2 of the PSA. Further discussions with HLP provided the following insights. Maintenance unavailabilities accentuate failures of DG's at time zero. Furthermore, site specific data for restoration of offsite power indicates less likelihood of recovery at times after one hour than is provided by generic recovery data. These two factors account for the relatively high values for DG failures with failure to restore offsite power.

STP has only one turbine driven, DC controlled AFW train. An additional AC independent AFW train would lower those sequence frequencies where station blackout is followed by loss of all AFW. However, replacement of an existing AC dependent AFW train with another AC independent AFW train should not significantly lower the overall core melt frequency. Such a replacement would result in LOSP sequence models involving loss of all feedwater, with failure of two diesel generators and failure of two turbine driven AFW trains. LOSP sequences involving loss of all feedwater currently include failures of three DGs and failure of one turbine AFW train. The failure rates for a DG and for a turbine driven AFW pump are numerically close. Split fraction G1 (one DG fails) is 0.12 and split fraction AFR (one AFW train fails) is 0.11. Thus, replacement of one motor driven AFW train with another turbine driven AFW train should not provide significant benefits.

The two units at STP are totally separated except for the common main reservoir and essential cooling pond. This separated design has advantages in that important support systems such as component cooling water and service water are not shared. However, the ability to manually cross tie between units could assist in recovery given an accident at one unit. The tradeoffs between enhanced recovery and the potential for additional, subtle failures arising from such a capability need to be evaluated before the effect of such a capability on core melt frequency can be evaluated. Cross-tie capability has the potential for lowering core melt frequency.

A comparison was made of the human error rates (HERs) used in the STP PSA study to those rates used by other PRA studies. The majority of the STP values were higher than those used by other studies, the remainder were within the same range of values. The HER estimates are driven by plant specific operator input into the HER method. The STP PSA analysts feel that the relatively high HER estimates accurately reflect operator judgment and experience.

5.2 Importance of Station Blackout

Of the twenty one dominant sequences, ten involve station blackout; eight are initiated by loss of offsite power and two are initiated by loss of EAB HVAC. Loss of EAB HVAC results in overheating of electrical switchgear which renders all 4160 Vac and 480 Vac safety related power unavailable even without loss of offsite power. Following station blackout, core melt occurs due to loss of turbine driven AFW train D in five of these sequences, while core melt occurs due to loss of PDP RCP seal injection in four of these sequences. Core melt occurs due to failure of a pressurizer PORV to reclose in one of these sequences.

The STP PSA concludes that 53% of overall core damage is due to loss of offsite power as an initiating event. Of the twenty one dominant sequences, thirteen are initiated by loss of offsite power and of these thirteen, eight lead to station blackout. Additional station blackout sequences arise from overheating of electrical switchgear due to loss of EAB HVAC. Thus, station blackout contributes substantially to the overall core melt frequency. This is consistent with results from PRAs of other nuclear power plants.

5.3 Contribution of LOCAs to Core Melt

LOCAs as initiating events contribute little to core melt. [Reference 1, Table 2.2-1] None of the twenty one dominant sequences are initiated by a LOCA. This is due to the fact that the ECCS pumps are self cooled and the PSA assumed that no forced cooling is required for the ECCS pump rooms. This lack of support system dependency for the ECCS pumps renders their failures relatively unlikely. Also, switchover of ECCS from injection to recirculation is automatic at STP; thus operator error does not contribute to failure to switchover to recirculation as it does at other plants.

Transients leading to small LOCAs and seal failures occur in five of the twenty one dominant sequences. In each of these five sequences, ECCS is unavailable due to station blackout. Four of the five sequences involve RCP seal failure due to loss of PDP supplied seal injection; one sequence involves a stuck open pressurizer PORV.

6.0 FIRE ANALYSIS REVIEW

6.1 Fire PSA Results

The conclusion of the fire PSA was that all areas outside the control room could be screened from further analysis based on screening guidelines delineated in Chapter 8 of the PSA. The control room had a detailed fire-risk assessment performed. It was determined that there were three dominant fire scenarios.

6.2 Review of Fire PSA

In November 1989, a plant visit and walkdown were conducted prior to receiving the STP PSA and fire hazard analysis. Based on this plant walkdown and information provided by the utility at that time, a letter requesting additional information was written. A reply to this information request was received on May 1, 1990. A copy of these questions and the STP reply is provided in Appendix 6.

Based on these responses and review of the STP PSA and fire hazard analysis which were received in February 1990, an additional list of questions was provided to the utility in June 1990. These additional questions were responded to and are given in Appendix 6. A September 1990 meeting was held in Washington to discuss the responses to these questions and any additional topics from the PSA documentation.

Following this September meeting there was a follow-up plant visit in October during which the critical fire areas (ranked on a core damage frequency basis) were examined. Also, three additional questions which could not be addressed during the September meeting were discussed. Written response to these questions is provided in Appendix 6. Three final questions were submitted to the utility during the plant visit and a response was received in February 1991. These questions and the utility response are also provided in Appendix 6.

This review made use of the PSA documentation itself and the additional documentation that had been provided by the utility during the review process. A core damage frequency point estimate spot check was performed for three of the critical fire areas.

The South Texas plant has an independent three safety train design. In most plant areas, as is typical of all previous fire PRAs, fire-induced core damage scenarios are insignificant contributors to overall core damage frequency. If only one safety train can be affected by a fire scenario, two additional trains are still available and must randomly fail. A fire which disables only one safety train and causes a turbine trip could be compared to the case of two train PWRs where a turbine trip has occurred. Since a fire in any given zone is much lower in frequency than turbine trips, screening areas from consideration where only single safety trains could be affected is entirely appropriate. By this consideration alone most South Texas fire zones can be shown to be insignificant contributors to overall core damage frequency.

6.3 Conclusions

A number of general conclusions in regards to the documentation and methodology employed in the PSA itself are as follows:

a. The STP fire PSA as it is currently written as a stand-alone document is unreviewable. Substantial additional information as is provided in Appendix 6 of this report would have to be included in the documentation to allow for reproducibility of the results of the analysis.

b. Sandia agrees with the STP fire PSA conclusion that areas outside the control room are non-dominant (less than 1%) contributors to total core damage frequency.

c. The screening criteria used to eliminate fire scenarios under consideration has screened scenarios and end states with potentially higher fire-induced core damage contributions than those areas that ultimately survived screening process. This screening process compared fire scenarios and fire event tree end states with similar internal event scenarios and end states. Therefore, if fire scenarios alone are considered, significant fire contributors may have been screened.

   In the utilities response to review question four (see Page 239 in Appendix 6), it is stated that the successive screening process was designed to systematically examine every potentially important fire zone and to identify those fires that could be quantitatively significant to the frequency of core damage and plant risk. It is further stated that this process was not designed to precisely quantify the total frequency of core damage that may be attributed to all possible fires in the plant.

   After an extensive review of this screening process, it is agreed that any significant fire-induced contributors to overall core damage frequency would not have been eliminated from further consideration.

d. Geometry and severity factors as given in the STP PSA Table 9.3-8 appeared to be nonconservative as compared with similar factors in other fire PRAs. It must be noted that a sensitivity analysis was performed to assess the effect of these factors. A list of fire zones which do not meet the screening criteria before application geometry and severity factors is provided in Appendix 6. This sensitivity study found eleven fire zones which in total could contribute 1.5E-5/yr to core damage frequency if the geometry/severity factors were taken to be unity.

   With the aid of some additional information that was provided by the utility in review question four (see Page 239 in Appendix 6), it is assessed that geometry/severity factor calculation is actually conservative but the degree of conservatism is unknown.

e. The fire risk for the STP control room is an order of magnitude lower than what has typically been found in other fire PRAs. This difference is the result of assignment of lower severity factors than have been used in other studies. A sensitivity analysis has been provided by the utility to assess the effect of including one additional larger fire event in the data base used to determine the severity factor probability assignment.

   A detailed description of the methodology and its application to three critical fire zones is given in the following sections.

6.4 <u>Methodology and Application to Zone 4 - ESF-A Switchgear Room</u>

A detailed description of the analysis performed for fire zone 4 was provided in response to questions provided to the utility in June 1990. This description is given in Appendix 6 (see Page 229). Fire zone 4 will be used as an example to discuss the fire methodology that was employed for all other areas except the control room. The evaluation methodology described in this response was applied to each of the 190 fire zones identified in STP PSA Table 8.5-2.

To derive fire scenario frequencies a five-step procedure was used. These five steps partitioned overall auxiliary building fire frequency to the specific zone of interest. As was the case for the control room, generic data which are the basis of the overall building fire frequency are not given. The point estimate overall building fire frequency is also not given. Therefore, insufficient documentation exists presently to independently derive zone specific fire frequencies.

Modification factors to the fire frequency are applied to account for specific combustibles located within the area, zone occupancy, and traffic characteristics. It is stated in the utility's response that these factors were assigned based on engineering judgment. Documentation on the rules for assignment of these parameter values is provided in the utility response to a final set of three questions in Appendix 6 (see Page 330). It was noted during the September meeting and review question three that these factors had little effect on any specific zone's fire frequency.

These weighting rules, as shown in Table 1 of review question three, were applied to 95 of the 111 fire zones in the Mechanical Auxiliary Building. It can be seen that these modification factors can range from a factor of eight decrease in fire frequency to an eighty seven percent increase in fire frequency. While the modification factor probability assignments appear to be reasonable, further justification into their derivation based on actual fire occurrence data seems warranted. For the remaining sixteen fire zones in the Mechanical Auxiliary Building additional modification factor adjustments were made. For fire zones where these additional adjustment factors decreased core damage frequency estimates, a sensitivity study was performed. This sensitivity study insured (for the areas with frequency reductions) that fire zone core damage frequency would remain below 0.1 percent of the overall total core damage frequency if the modification factor was set to unity.

When comparing the fire frequency assigned for ESF-A switchgear room fire zone 4 and the generic switchgear room fire frequency developed for NUREG/CR-4840, [26] fire zone 4 had a frequency which is 55% lower. Therefore, the STP fire frequency estimate may potentially underestimate risk by up to a factor of two and sufficient documentation is not currently available to reproduce the results of the analysis.

The second step in the methodology was identification of component and system impact for fire scenarios within the zone. Table D-6 in Appendix D of the STP PSA contains inventories of PRA-related equipment and cables located in each fire zone.

For fire zone 4 most potential failures were to train A equipment. However, Table 4-2 through Table 4-4 in Appendix 6 (see Pages 244 and 247) also note other important impacts on equipment in other ESF trains and non-ESF equipment. This documentation is necessary to determine what additional random failures (non-fire related failures in other areas) are required for any given scenario to lead to core damage.

The possible impacts of any fire scenario were categorized according to the four classes described in the STP PSA Section 8.5.3. These four classes are as follows:

- Class 0. Scenario does not affect any system and does not cause any initiating event in the plant model.
- Class 1. Scenario causes an initiating event and may or may not affect any system.
- Class 2. Scenario affects one or more trains of a single system only.
- Class 3. Scenario affects one or more trains of more than one system.

For the fire scenarios in zone 4 it was determined that an initiating event would occur (Class 1) and more than one ESF train would be affected (Class 3).

The next step in the methodology compared the frequency of the fire scenario with the corresponding frequency of the same outcomes caused by an internal initiating event and random system failures. This comparison given on Table 4-5 of Appendix 6 (see Page 249) shows that the possible fire-induced failures are not numerically bounded by the corresponding combinations of internal events. It must be noted that more than one hundred fire scenarios were eliminated in this screening step. Some of these scenarios potentially have a frequency of fire-induced core damage greater than the fire scenarios that ultimately survived the screening process. Therefore, a comprehensive ranking of all fire scenarios was not performed. It should be noted that no reduction factors were applied at this point of the evaluation and that most of the eliminated scenarios would probably have a negligible contribution to fire-induced core damage frequency.

The final step of the methodology developed fire scenario event trees and impact end states. These event trees took into account what the fire-induced equipment failure modes were and also identified simple operator recovery actions that could mitigate the fire impacts through manual operation of components or use of alternate equipment not affected by the fire. Figure 4-1 in Appendix 6 (see Page 266) shows the event tree for fire zone 4. After completion of the fire scenario event trees, three additional screening steps were applied.

In the first of these additional screening steps, each end state frequency was compared with the corresponding frequency of the same set of combined outcomes caused by an internal initiating event and random system failures. Once again, this step can eliminate potentially important fire contributors to core damage frequency when the comparison is only with all other fire-induced end states alone. Therefore, knowledge of overall fire-induced core damage frequency is precluded by this screening step. Table 4-8 of Appendix 6 (see Page 252) gives this comparison for fire zone 4.

In the second additional screening step, the random system failures that are required to lead to core damage are analyzed. The number, types, and combinations of these additional failures depend on the specific impacts caused by the fire scenario end state. These random failures are given for two of these end states (11 and 12) in Figure 4-1 in Tables 4-10 and 4-11 (see Pages 258 and 259), respectively. As was previously mentioned, these random failure cut sets are required to reproduce core damage frequency estimates for any fire scenario. It is stated in the utility response that the original fire scenario evaluations were based on conservative intermediate results of the internal events quantification. This screening step is entirely consistent with the methodology employed in the NUREG-1150 and other fire PRAs. In this second level of additional screening, a fire scenario end state was eliminated from further consideration if its total core damage frequency contribution was less than one-tenth of one percent of the total core damage frequency from internal events, i.e., less than 1.7E-7 per year. Once again, when comparisons are made for fire sequences only, some potentially significant fire sequences may be eliminated.

In the third level of screening, reduction factors were applied to account for fire zone geometry and the severity of fires necessary to damage critical sets of equipment and cables. The derivation of the reduction factors for fire zone 4 end state 11 is given in Attachment 4.2 in Appendix 6 (see Page 273). Each reduction factor represents the approximate conditional probability that any fire in zone 4 damages the identified set of components. All other impacts were assumed to remain the same as in the preceding levels of the analysis.

It is stated on page 9.3-2 of the STP PSA that "we do not know exactly how the cables are routed through the fire zone". If it was not known where the cables were located, assignment of these reduction factors yields little physical insight into the actual fire propagation scenario within fire zone 4 or any of the other fire zones where they were applied.

In past PL&G fire PRAs and for the NUREG-1150 fire analyses, the COMPBRN fire propagation code [27] was used to determine fire zone geometry and severity factors. In some cases hot gas layer predictions led to unity assignment for both area and severity ratios. Table 9.3-8 of the STP PSA gives geometry/severity factor reduction for fire scenario Z052-FS-01 and Table 4-13 in Appendix 6 (see Page 261) gives the reduction factors for fire scenario Z004-FS-01 end states 11 and 12. These combined reduction factors range from 0.16 to 4.8E-3. The reduction factor analysis for fire scenario Z004-FS-01 is documented in Attachment 4.2 in Appendix 6.

A number of fire sources are postulated. These sources are breakers, transformers, busses, cabling, and transient fires. To determine the fire frequency for any specific breaker, transformer, or bus within fire zone 4, partitioning occurred based on the generic data base (which is not provided) and the number of each of these types of equipment within the respective fire zone. What is not known in this partitioning process is how many of each type of equipment (weighted average) are in a typical switchgear room for any given plant in the generic data base. Without this additional information, partitioning fire frequency by this method could either overestimate or underestimate any given component's fire frequency. For example, if an typical plant has only one hundred breakers per switchgear room, then each individual breaker at that plant would have double the fire frequency of the breakers found in fire zone 4. The same comment can equally be applied to both the transformer and bus fire partitioning factors.

For cable fire partitioning, it is assumed that any critical set of cables has a run length of 124 ft and a width of 2 ft. It is stated in Attachment 4.2 that it appears that the total cable tray area is greater than the floor area of the room itself. The cable fire frequency is then partitioned by use of the generic fire data base and the amount of critical cabling within the area as compared to the total cabling. It appears that this partitioning is conservative but the degree of conservatism cannot be assessed without knowledge of actual length of critical cabling within the fire zone.

For partitioning of transient combustible fires, the combined geometry/severity factor yields a reduction factor of approximately 0.2. This analysis also appears to be conservative but the degree of conservatism cannot be assessed without knowledge of critical cabling locations.

It is also noted that 10% of all fires are assumed to be "large" and lead to the loss of all equipment within the room. This essentially analyzes the case of hot gas layer formation where all equipment in this layer is assumed to be failed. Based on the October 1990 plant walkdown and many previous COMPBRN code calculations, this 10% assumption is conservative.

Many conservatisms have been employed in the analysis of reduction factors for fire zone 4. The reduction in core damage frequency due to these conservatisms, however, cannot be assessed. One potential non-conservatism does exist in this partitioning analysis. As was previously stated, how transformer, breaker, and bus loading in fire zone 4 compares with an typical plant is unknown. This could lead to either an increase or decrease in core damage frequency estimates of up to a factor of three based on walkdowns of other plants.

If it is assumed that both the geometry and severity reduction factors are unity and the NUREG-1150 switchgear room fire frequency is used, then fire zone 4 would have a core damage frequency of 3.98E-6/yr. This frequency can be considered a bounding estimate. A best estimate based on known cabling locations would probably yield at least an order of magnitude reduction from this conservative estimate.

6.5 Fire Zone 47 - Cable Spreading Room

The same methodology steps that were applied to fire zone 4 were also used in the analysis of fire zone 47.

Fire frequency was derived by partitioning auxiliary building fire data. This partitioning method is inconsistent when compared with cable spreading room fire frequency derivation in past fire PRAs. Previous fire PRAs have developed frequencies from cable spreading fire experience alone and not considered partitioning (of fire data) from the building where the cable spreading room is located. When compared with the NUREG-1150 generic cable spreading room fire frequency, fire zone 47 has a fire frequency which is approximately 20 percent higher.

HLP performed a sensitivity study to assess the effect on core damage frequency of fire frequency assignment for fire zones listed in the cable spreading category. To account for the possibility that STP has more cable spreading area than a typical plant, the generic fire frequency was increased by 50% to 1.0E-2/yr. This fire frequency was then partitioned by floor area to each of the five cabling spreading room fire zones. For fire zone 4 and the other four fire zones little modification to the initially calculated core damage frequency estimates is noted.

An additional sensitivity study performed by HLP and given in Appendix 6 (see Page 217) assumed both the geometry and severity factors were unity for fire zone 47. The sensitivity study found four end states with a total core damage frequency contribution of 1.34E-6/yr. This should be considered a bounding estimate of fire-induced core damage frequency. A best estimate frequency would consider actual cable locations as well as allow credit for the automatic water fire protection system which provides room wide coverage. Both of these considerations would lower this bounding core damage frequency estimate by at least a factor of 20 since generic reliability values for automatic water fire protection systems are approximately 95%.

6.6 Control Room Fire Analysis

The quantification procedure employed in the STP PSA for the control room is consistent with that used in previous fire PRAs except for the assignment of credit for manual fire suppression. An overall control room fire frequency is developed and then partitioned based on cabinet area to develop cabinet-specific fire frequencies. Even though the generic fire data is not given that was used in frequency assignment, the overall frequency is within 10% of the value used in NUREG-1150.[25] Cabinet area ratios are plant-specific and, therefore, cannot be directly compared with any other fire PRAs.

Differences arise as to how credit is given for manual suppression of a fire before critical damage is sustained in this continually manned area. In the NUREG-1150 fire analyses, an order of magnitude reduction in cabinet fire frequencies gave credit for manual suppression while in STP fire PSA the severity ratio is assigning a similar type of credit. STP severity ratios ranged from 0.072 to 0.0015.

For the dominant scenarios (numbers 18 and 23) severity factor assignments were 3.7E-3 and 3.2E-3, respectively. These lower probabilities of fire damage to critical equipment before manual suppression account for most of the difference in the control room core damage frequency estimation between NUREG-1150 and the STP fire PSA.

In both studies and also in other fire PRAs, credit is also given for recovery from a remote shutdown panel. In the case of the STP fire PSA, it is also assumed that for some fraction of control room fires recovery actions take place in the control room itself. It must be noted that for an unsuppressed control room fire Sandia fire testing experience has indicated that smoke rapidly descends (6 to 8 minutes) to the floor making operator actions within the control room a virtual impossibility in diameter. [26] However, the recovery actions for the STP control room fire analysis were not explicitly stated and the probability assignment appears to be conservative.

A sensitivity analysis was performed by the utility to assess the effect on severity factor probability assignment by adding one additional larger cabinet fire than any other fire already in the the PL&G cabinet fire data base. A graph representing this sensitivity study is given in Appendix 6 (see Page 291). For cabinet fires which are less than one foot or greater than five feet in diameter, little modification occurs in severity factor assignments. For fires between one to five feet, up to a factor of three increase in the severity factor can occur. Fire area of influence in the range of one to five feet is typical of most critical control room fire scenarios. It is concluded that the severity factor probability assignment utilized for STP results in up to a factor of thirty decrease in core damage frequency estimates from previous fire PRAs and is somewhat sensitive to which fire events are included or excluded from consideration.

6.7 Recommendations

It is recommended that:

a. Additional information as given by the utility in response to review questions should be provided in the fire PSA to allow a reader to reproduce the results.

b. Fire event data that was used in the severity factor calculation for the control room and the fire frequency determinations for all plant areas should be included. Once again, this would allow the reader to reproduce the results of the analysis.

c. A more detailed derivation of control room fire scenario operator recovery probability would yield greater insight into the dominant fire-induced core damage frequency scenarios.

7.0 CONCLUSIONS FOR INTERNAL EVENTS ANALYSIS

This section summarizes the conclusions of this review with respect to internal events.

In general, the STP PSA is a state-of-the-art Level 1 risk assessment. The detail to which the plant was modeled and the engineering analyses justifying this model are good, although certain parts of the analyses are not sufficiently justified. Section 5.4 and the System Descriptions of the PSA document the plant model. The PLG methodology is described, but its application to STP is not always clearly explained. Several major components of the methodology, such as HRA, uncertainty analysis, and split fraction definition and quantification, had to be explained and illustrated in detailed presentations by HLP and PLG personnel to the reviewers. A simple example of the methodology would aid in understanding the nuances of the techniques.

The dominant sequences are not clearly described in the PSA. Split fractions and basic events which contribute significantly to each dominant sequence are not readily identified or clearly displayed. Review of the PSA methods, their application to STP, and interpretation of the dominant sequences would have been difficult without the benefit of meetings and presentations involving the Sandia reviewers, STP PSA analysts, and PLG personnel. The most significant concern regarding the PSA report is a lack of documentation to support the Human Error Analysis.

Despite the difficulties in understanding the documentation, the PSA analysis was well done. The STP PSA analysts exhibited a clear understanding of the PLG methods. Their application of these methods to STP was proper. The level of detail of the models was quite high and consistent with current state-of-the-art PRAs. Whenever concerns regarding PSA models, assumptions, data, or methods arose during the review, these concerns were explained satisfactorily to the review staff.

A summary of those review comments previously specified in this report as potential problems resolved, is as follows:

- The time to steam generator dryout following loss of all feedwater is not fully justified. (Section 2.1.1 of this report)

- The ability of equipment in the ECCS pump rooms to operate without forced cooling to the rooms is not fully justified. (Section 2.2.3 of this report)

- The confusion regarding the labeling of split fractions AFP, AFQ, and AFO in the dominant sequences (Table 3.6-1) should be resolved. (Section 3.6 of this report)

A summary of those review comments previously specified as items insufficiently explained, is as follows:

- Quantification of the split fraction labeled PTS is not clearly provided. (Section 2.1.1 of this report)

- The use of the nomenclature "hot standby" and "hot shutdown" are inconsistent with the definitions in the Technical Specifications. (Section 2.1.1 of this report)

- Accumulator injection following large or medium LOCAs is assumed to not be required. This assumption is not justified. (Sections 2.1.2 and 2.1.3 of this report)

- The effect of early failure-to-isolate containment on reflood, following a large LOCA, is not addressed. (Section 2.1.2 of this report)

- The need to switchover from cold to hot leg recirculation to avoid boron precipitation is not addressed. (Section 2.1.2 of this report)

- The instrument tube breach as a potentially unique small LOCA is not discussed. (Section 2.1.4 of this report)

- The STP V sequence model does not completely address the following issues:

  - The value for check valve rupture failure rate is significantly lower than the value in the PSA data base.

  - The ability of the MOV in the LHSI-RCS cold leg path to close against reverse flow has not been established.

  - The utility has not stated which of three V sequence scenarios is the most appropriate for the STP PSA. (Section 2.1.6 of this report)

- A discussion of the letdown line break is not provided. (Section 2.1.6 of this report)

- Minimum containment cooling requirements are not sufficiently discussed. (Section 2.1.8 of this report)

- The assumption that the containment never fails early is not discussed. (Section 2.1.8 of this report)

- The three-inch criterion for containment pressurization is not justified. (Section 2.1.8 of this report)

- I&C necessary for throttling HHSI is not included. (Section 2.2.2 of this report)

- The ability of equipment in the PDP pump room to operate without forced cooling to the room is not justified. (Section 2.2.3 of this report)

- The exclusion of IA from the mitigating systems is not clearly justified. (Section 2.2.5 of this report)

- The ability of EAB HVAC to provide adequate cooling in a once through mode with no cooling provided to AHUs is not explicitly justified. (Section 2.3.2 of this report)

- The acceptability of one steam generator in removing decay heat without its PORV being available is not clarified in the System Description for AFW. (Section 2.3.2 of this report)

- The screening of high and medium energy line breaks and cracks as initiating events except for LOCAs, main steam line breaks, and feedwater line breaks is not justified. (Section 3.1 of this report)

- The justification for excluding core blockage as an initiating event is not provided. (Section 3.1 of this report)

- The majority of the values used for the Human Error Rates (HERs) are conservative, the remainder are similar to values used in other PRA studies. The HER values used do not seem unreasonable but the derivation of these estimates is not well documented. (Section 3.4.5 of this report)

- The table of the twenty one dominant sequences which identifies split fractions contributing to each sequence, Table 3.6-1 is not included in the PSA. (Section 3.6 and Section 4.3 of this report)

- Quantification of LOSP sequences are such that the exposure time for the DGs and the time for recovery of offsite power are inconsistent. (Section 5.1 of this report)

All of these items were resolved by HLP as provided in the detailed responses of Appendix 3 and 4. These responses were previously summarized in the main sections of this report where the specific items were individually discussed.

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Appendix 1: LIST OF ACRONYMS

AFW	Auxiliary Feedwater
AFWST	Auxiliary Feedwater Storage Tank
AHU	Air Handling Unit
AOV	Air-Operated Valve
ATWS	Anticipated Transient Without Scram
CCF	Common Cause Failure
CCW	Component Cooling Water
CDF	Core Damage Frequency
CET	Containment Event Tree
CIS	Containment Isolation System
CSS	Containment Spray System
CST	Condensate Storage Tank
CVCS	Chemical and Volume Control System
DCH	Direct Containment Heating
DG	Diesel Generator
DHR	Decay Heat Removal
DPD	Discrete Probability Distribution
EAB	Electric Auxiliary Building
ECCS	Emergency Core Cooling System
ECP	Essential Cooling Pond
ECW	Essential Cooling Water
EOP	Emergency Operating Procedure
ESD	Event Sequence Diagram
ESF	Engineered Safety Feature
ESFAS	Engineered Safety Feature Actuation System
FC	Fail Closed
FHB	Fuel Handling Building
FMEA	Failure Modes and Effects Analysis
FO	Fail Open
FSAR	Final Safety Analysis Report
HBFT	Heat Balance Fault Tree
HEPA	High Efficiency Particle Air
HER	Human Error Rate
HHSI	High Head Safety Injection
HL&P	Houston Lighting & Power Company
HPI	High Pressure Injection
HVAC	Heat, Ventilating, and Air Conditioning
I&C	Instrumentation and Control
IPE	Individual Plant Examination
IVC	Isolation Valve Cubicle
LCO	Limiting Conditioning for Operation
LHSI	Low Head Safety Injection
LOCA	Loss of Coolant Accident
LOOP	Loss Of Offsite Power (preferred)

LOP	Loss of Power
LOSP	Loss of Offsite Power
LWR	Light Water Reactor
MAB	Mechanical Auxiliary Building
MCC	Motor Control Center
MDP	Motor-Driven Pump
MFW	Main Feedwater
MGL	Multiple Greek Letters
MLD	Master Logic Diagram
MOV	Motor-Operated Valve
MSIV	Main Steam Isolation Valve
MSL	Mean Sea Level
NPSH	Net Positive Suction Head
NRC	U.S. Nuclear Regulatory Commission
O&M	Operation and Maintenance Manual
PDP	Positive Displacement Pump
PDS	Plant Damage State
P&ID	Piping and Instrumentation Diagram
PLG	Pickard, Lowe and Garrick, Inc.
PORV	Power-Operated Relief Valve
PRA	Probabilistic Risk Assessment
PSA	Probabilistic Safety Assessment
PSF	Performance Shaping Factor
PTS	Pressurized Thermal Shock
PWR	Pressurized Water Reactor
QA	Quality Assurance
QDPS	Qualified Display Processing System
RCB	Reactor Containment Building
RCFC	Reactor Containment Fan Cooler
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RWST	Refueling Water Storage Tank
SBO	Station Blackout
SCS	Secondary Coolant System
SGTR	Steam Generator Tube Rupture
SIS	Safety Injection System
SRV	Safety Relief Valve
SSE	Safe Shutdown Earthquake
SSPS	Solid State Protection System
STP	South Texas Project
TBS	Turbine Bypass System
TBV	Turbine Bypass Valves
TDP	Turbine-Driven Pump

Appendix 2: Table 3.6-1
Additional Analysis of Top-Ranking Sequences for Mean Core Damage Frequency
(Sequence 1)

Sequence Element	Event Description	Mean Frequency (per year)	Split Fraction Identifier	Reference (PSA)
Initiating Event	Loss of Offsite Power	9.0×10^{-2}	LOSP	Chapter 7.6 (See Note 1 Below)
System Failures Following Initiating Event	All Three Diesel Generators Supplying Safety Related 4160V Buses	4.5×10^{-3}	G3	Appendix F: Book 1
	Turbine Driven Auxiliary Feedwater Pump	1.1×10^{-1}	AFR	Appendix F: Book 9
Recovery Actions	Failure to Recover Auxiliary Feedwater Before Steam Generator Dryout (See Note 2 Below)	8.0×10^{-1}	RECV5	Chapter 5.6
	Failure to Recover Offsite Power Within One Hour	4.7×10^{-1}	ORL	Chapter 15.6
	Failure to Recover at Least One Failed Diesel Generator Within One Hour	8.4×10^{-1}	OMC	Chapter 15.6
	Total Sequence Frequency (See Note 3 Below)	1.2×10^{-5}		

Note 1: LOSP initiating Event Frequency is given as 1.29×10^{-1} events per year in Table 7.6-1. Since this frequency is based on a calendar year, a 0.7 factor is applied to account for the time that the plant is at power. This applies to all sequences with the LOSP initiator.

Note 2: Combination of Equipment Failures Not Recoverable Before Steam Generator Dryout and Operator Errors During Auxiliary Feedwater Recovery. This also applies to all sequences with the RECV5 recovery factor.

Note 3: The Frequency for Successful Operation of the Remaining Systems is not shown, but is included in the Total Sequence Frequency. This applies to each sequence identified in this table.

Appendix 2: Table 3.6-1 (Cont.)
Additional Analysis of Top-Ranking Sequences for Mean Core Damage Frequency
(Sequence 2)

Sequence Element	Event Description	Mean Frequency (per year)	Split Fraction Identifier	Reference (PSA)
Initiating Event	Loss of Offsite Power	9.0×10^{-2}	LOSP	Chapter 7.6
System Failures Following Initiating Event	Diesel Generators A and C,	1.9×10^{-2}	G2	Appendix F: Book 1
	Essential Cooling Train B (Hence Diesel Generator B)	1.3×10^{-1}	WBE	Appendix F: Book 4
	Turbine Driven Auxiliary Feedwater Pump	1.1×10^{-1}	AFR	Appendix F: Book 9
Recovery Actions	Failure to Recover Auxiliary Feedwater Before Steam Generator Dryout	8.0×10^{-1}	RECV5	Chapter 5.6
	Failure to Recover Offsite Power Within One Hour	4.7×10^{-1}	ORK	Chapter 15.6
	Failure to Recover at Least One Failed Diesel Generator With One Hour	8.4×10^{-1}	OMB	Chapter 15.6
	Total Sequence Frequency	5.6×10^{-6}		

Appendix 2: Table 3.6-1 (Cont.)
Additional Analysis of Top-Ranking Sequences for Mean Core Damage Frequency
(Sequence 3)

Sequence Element	Event Description	Mean Frequency (per year)	Split Fraction Identifier	Reference (PSA)
Initiating Event	Loss of Electrical Auxiliary Building HVAC Cooling	6.0×10^{-5}	LOEAB	Chapter 7.6
System Failures Following Initiating Event	All Three Safety Related 4160V Buses (Direct Failure)	1.00	N/A	N/A
	Turbine Driven Auxiliary Feedwater Pump	1.1×10^{-1}	AFR	Appendix F: Book 9
Recovery Actions	Failure to Recover Turbine Driven Auxiliary Feedwater Pump Before Steam Generator Dryout	8.0×10^{-1}	RECV5	Chapter 5.6
	Total Sequence Frequency	4.5×10^{-6}		

Appendix 2: Table 3.6-1 (Cont.)
Additional Analysis of Top-Ranking Sequences for Mean Core Damage Frequency
(Sequence 4)

Sequence Element	Event Description	Mean Frequency (per year)	Split Fraction Identifier	Reference (PSA)
Initiating Event	Loss of Electrical Auxiliary Building HVAC Cooling	6.0×10^{-5}	LOEAB	Chapter 7.6
System Failures Following Initiating Event	All Three Safety Related 4160V Buses (Direct Failure	1.0	N/A	N/A
	Positive Displacement Charging Pump (Seal LOCA - No Makeup)	9.3×10^{-2}	PDH	Appendix F: Book 10
Recovery Actions	None	N/A	N/A	N/A
	Total Sequence Frequency	4.3×10^{-6}		

Appendix 2: Table 3.6-1 (Cont.)
Additional Analysis of Top-Ranking Sequences for Mean Core Damage Frequency
(Sequence 5)

Sequence Element	Event Description	Mean Frequency (per year)	Split Fraction Identifier	Reference (PSA)
Initiating Event	Loss of Offsite Power	9.0×10^{-2}	LOSP	Chapter 7.6
System Failures Following Initiating Event	Diesel Generators A and B,	1.9×10^{-2}	G2	Appendix F: Book 1
	Electrical Auxiliary Building HVAC Fan Train C	4.5×10^{-2}	FCM	Appendix F: Book 6
	Technical Support Center Diesel Generator and Positive Displacement Charging Pump	2.0×10^{-1}	PDJ	Appendix F: Book 10
Recovery Actions	Failure to Recover Offsite Power Before Switchgear Overheats	4.7×10^{-1}	ORK	Chapter 15.6
	Failure to Recover at Least One Failed Diesel Generator Before Switchgear Overheats	8.4×10^{-1}	OMB	Chapter 15.6
	Total Sequence Frequency	3.6×10^{-6}		

Appendix 2: Table 3.6-1 (Cont.)
Additional Analysis of Top-Ranking Sequences for Mean Core Damage Frequency
(Sequence 6)

Sequence Element	Event Description	Mean Frequency (per year)	Split Fraction Identifier	Reference (PSA)
Initiating Event	Loss of Offsite Power	9.0×10^{-2}	LOSP	Chapter 7.6
System Failures Following Initiating Event	Diesel Generator A;	1.2×10^{-1}	GAA	Appendix F: Book 1
	Essential Cooling Train B (Diesel Generator B); and	1.3×10^{-1}	WBE	Appendix F: Book 4
	Electrical Auxiliary Building HVAC Train C	4.5×10^{-2}	FCM	Appendix F: Book 6
	Technical Support Center Diesel Generator and Positive Displacement Charging Pump	2.0×10^{-1}	PDJ	Appendix F: Book 10
Recovery Actions	Failure to Recover Offsite Power Before Switchgear Overheats	4.7×10^{-1}	ORJ	Chapter 15.6
	Failure to Recover at Least One Switchgear Failed Diesel Generator Before Overheats	8.4×10^{-1}	OMA	Chapter 15.6
	Total Sequence Frequency	2.6×10^{-6}		

Appendix 2: Table 3.6-1 (Cont.)
Additional Analysis of Top-Ranking Sequences for Mean Core Damage Frequency
(Sequence 7)

Sequence Element	Event Description	Mean Frequency (per year)	Split Fraction Identifier	Reference (PSA)
Initiating Event	Reactor Trip	$1.4 \times 10^{+0}$	RT	Chapter 7.6
System Failures Following Initiating Event	No System Failures - Failure of Long-Term Operator Actions to Stabilize the Plant	2.7×10^{-6}	ONA	Chapter 15.4
Recovery Actions	None	N/A	N/A	N/A
	Total Sequence Frequency	2.6×10^{-6}		

Appendix 2: Table 3.6-1 (Cont.)
Additional Analysis of Top-Ranking Sequences for Mean Core Damage Frequency
(Sequence 8)

Sequence Element	Event Description	Mean Frequency (per year)	Split Fraction Identifier	Reference (PSA)
Initiating Event	Partial Loss of Main Feedwater Flow	$1.1 \times 10^{+0}$	PLMFW	Chapter 7.6
System Failures Following Initiating Event	No System Failures - Failure of Long-Term Operator Actions to Stabilize the Plant	2.7×10^{-6}	ONA	Chapter 15.4
Recovery Actions	None	N/A	N/A	N/A
	Total Sequence Frequency	2.2×10^{-6}		

Appendix 2: Table 3.6-1 (Cont.)
Additional Analysis of Top-Ranking Sequences for Mean Core Damage Frequency
(Sequence 9)

Sequence Element	Event Description	Mean Frequency (per year)	Split Fraction Identifier	Reference (PSA)
Initiating Event	Turbine Trip	$1.1 \times 10^{+0}$	TT	Chapter 7.6
System Failures Following Initiating Event	No System Failures - Failures of Long-Term Operator Actions to Stabilize the Plant	2.7×10^{-6}	ONA	Chapter 15.4
Recovery Actions	None	N/A	N/A	N/A
	Total Sequence Frequency	2.0×10^{-6}		

Appendix 2: Table 3.6-1 (Cont.)
Additional Analysis of Top-Ranking Sequences for Mean Core Damage Frequency
(Sequence 10)

Sequence Element	Event Description	Mean Frequency (per year)	Split Fraction Identifier	Reference (PSA)
Initiating Event	Loss of Offsite Power	9.0×10^{-2}	LOSP	Chapter 7.6
System Failures Following Initiating Event	Diesel Generators A and B	1.9×10^{-2}	G2	Appendix F: Book 1
	Turbine Driven and Motor Driven Train C Auxiliary Feedwater Pumps	4.9×10^{-3}	AFP	Appendix F: Book 9
	Closed Loop RHR Cooling Disabled	1.0	N/A	N/A
Recovery Actions	Failure to Recover Offsite Power Within One hour	4.7×10^{-1}	ORK	Chapter 15.6
	Failure to Recover at Least One Failed Diesel Generator Within One Hour	8.4×10^{-1}	OMB	Chapter 15.6
	Total Sequence Frequency	2.0×10^{-6}		

Appendix 2: Table 3.6-1 (Cont.)
Additional Analysis of Top-Ranking Sequences for Mean Core Damage Frequency
(Sequence 11)

Sequence Element	Event Description	Mean Frequency (per year)	Split Fraction Identifier	Reference (PSA)
Initiating Event	Loss of Offsite Power	9.0×10^{-2}	LOSP	Chapter 7.6
System Failures Following Initiating Event	Diesel Generators A and B,	1.9×10^{-2}	G2	Appendix F: Book 1
	Electrical Auxiliary Building HVAC Train	4.5×10^{-2}	FCM	Appendix F: Book 6
	Turbine Driven Auxiliary Feedwater Train	1.1×10^{-1}	AFR	Appendix F: Book 9
Recovery Actions	Failure to Recover Offsite Power Before Switchgear Overheats	4.7×10^{-1}	ORK	Chapter 15.6
	Failure to Recover at Least One Failed Diesel Generator Before Switchgear Overheats	8.4×10^{-1}	OMB	Chapter 15.6
	Failure to Recover Auxiliary Feedwater Before Steam Generator Dryout	8.0×10^{-1}	RECV5	Chapter 5.6
	Total Sequence Frequency	1.9×10^{-6}		

Appendix 2: Table 3.6-1 (Cont.)
Additional Analysis of Top-Ranking Sequences for Mean Core Damage Frequency
(Sequence 12)

Sequence Element	Event Description	Mean Frequency (per year)	Split Fraction Identifier	Reference (PSA)
Initiating Event	Loss of Offsite Power	9.0×10^{-2}	LOSP	Chapter 7.6
System Failures Following Initiating Event	All Three Diesel Generators Supplying Safety Related 4160V Buses	4.5×10^{-3}	G3	Appendix F: Book 1
	Technical Support Center Diesel Generator and Positive Displacement Charging Pump	2.0×10^{-1}	PDJ	Appendix F: Book 10
Recovery Actions	Failure to Recover Offsite Power Within One Hour	4.7×10^{-1}	ORL	Chapter 15.6
	Failure to Recover at Least One Failed Diesel Generator Within One Hour	8.4×10^{-1}	OMC	Chapter 15.6
	Failure to Recover at Least One Failed Diesel Generator or Offsite Power Before RCP Seal LOCA Uncovers Core (Conditional on Failure to Recover Power Within One Hour)	7.7×10^{-2}	RECV2	Chapter 5.6
	Total Sequence Frequency	1.8×10^{-6}		

Appendix 2: Table 3.6-1 (Cont.)
Additional Analysis of Top-Ranking Sequences for Mean Core Damage Frequency
(Sequence 13)

Sequence Element	Event Description	Mean Frequency (per year)	Split Fraction Identifier	Reference (PSA)
Initiating Event	Loss of Offsite Power	9.0×10^{-2}	LOSP	Chapter 7.6
System Failures Following Initiating Event	Diesel Generator A;	1.2×10^{-1}	GAA	Appendix F: Book 1
	Essential Cooling Train B (Diesel Generator B); and	1.3×10^{-1}	WBE	Appendix F: Book 4
	Electrical Auxiliary Building HVAC Train C	4.5×10^{-2}	FCM	Appendix F: Book 6
	Turbine Driven Auxiliary Feedwater Train	1.1×10^{-1}	AFR	Appendix F: Book 9
Recovery Actions	Failure to Recover Offsite Power Before Switchgear Overheats	4.7×10^{-1}	ORJ	Chapter 15.6
	Failure to Recover at Least One Failed Diesel Generator Before Switchgear Overheats	8.4×10^{-1}	OMA	Chapter 15.6
	Total Sequence Frequency	1.7×10^{-6}		

Appendix 2: Table 3.6-1 (Cont.)
Additional Analysis of Top-Ranking Sequences for Mean Core Damage Frequency
(Sequence 14)

Sequence Element	Event Description	Mean Frequency (per year)	Split Fraction Identifier	Reference (PSA)
Initiating Event	Loss of Offsite Power	9.0×10^{-2}	LOSP	Chapter 7.6
System Failures Following Initiating Event	Diesel Generators A and C	1.9×10^{-2}	G2	Appendix F: Book 1
	Turbine Driven and Motor Driven Train B Auxiliary Feedwater Pumps	4.9×10^{-3}	AFP	Appendix F: Book 9
	Closed Loop RHR Cooling Disabled	1.0	N/A	N/A
Recovery Actions	Failure to Recover Offsite Power Within One Hour	4.7×10^{-1}	ORK	Chapter 15.6
	Failure to Recover at Least One Failed Diesel Generator Within One Hour	8.4×10^{-1}	OMB	Chapter 15.6
	Total Sequence Frequency	2.0×10^{-6}		

Appendix 2: Table 3.6-1 (Cont.)
Additional Analysis of Top-Ranking Sequences for Mean Core Damage Frequency
(Sequence 15)

Sequence Element	Event Description	Mean Frequency (per year)	Split Fraction Identifier	Reference (PSA)
Initiating Event	Loss of Offsite Power	9.0×10^{-2}	LOSP	Chapter 7.6
System Failures Following Initiating Event	Diesel Generators A and C,	1.9×10^{-2}	G2	Appendix F: Book 1
	Essential Cooling Train B (Hence Diesel Generator B)	1.3×10^{-1}	WBE	Appendix F: Book 4
	Pressurizer PORV Stuck Open	5.0×10^{-2}	PRA	Appendix F: Book 11
Recovery Actions	Failure to Recover Offsite Power Within One Hour	4.7×10^{-1}	ORK	Chapter 15.6
	Failure to Recover at Least One Failed Diesel Generator Within One Hour	8.4×10^{-1}	OMB	Chapter 15.6
	Failure to Recover Offsite Power or at Least One of the failed Diesel Generators Before the Core Uncovers due to the Stuck Open PORV (Conditional on Failure to Recover Power Within One Hour)	4.9×10^{-1}	RECV8	Chapter 5.6 (See Note 4 Below)
	Total Sequence Frequency	1.5×10^{-6}		

Note 4: During HL&P's Review, it was discovered that RECV7 is appropriate when two Diesel Generators Have Failed. RECV7 is 5.2×10^{-1}. As a result, the Sequence Total Frequency should be 1.6×10^{-6}.

Appendix 2: Table 3.6-1 (Cont.)

Additional Analysis of Top-Ranking Sequences for Mean Core Damage Frequency

(Sequence 16)

Sequence Element	Event Description	Mean Frequency (per year)	Split Fraction Identifier	Reference (PSA)
Initiating Event	Steam Generator Tube Rupture	2.8×10^{-2}	SGTR	Chapter 7.6
System Failures Following Initiating Event	Failure to Depressurize Reactor Coolant System Below Steam Generator PORV Setpoint	3.1×10^{-3}	ODA	Chapter 15.4
Recovery Actions	Failure to Cool Down and Align Plant for Closed Loop RHR Cooling	2.9×10^{-2}	OAA	Chapter 15.5
	Total Sequence Frequency	1.4×10^{-6}		

Appendix 2: Table 3.6-1 (Cont.)
Additional Analysis of Top-Ranking Sequences for Mean Core Damage Frequency
(Sequence 17)

Sequence Element	Event Description	Mean Frequency (per year)	Split Fraction Identifier	Reference (PSA)
Initiating Event	Loss of Offsite Power	9.0×10^{-2}	LOSP	Chapter 7.6
System Failures Following Initiating Event	Diesel Generator A;	1.2×10^{-1}	GAA	Appendix F: Book 1
	Essential Cooling Water Train B (Hence Diesel Generator B)	1.3×10^{-1}	WBE	Appendix F: Book 4
	Turbine Driven Train D and Motor Driven Train C Auxiliary Feedwater Pumps	4.9×10^{-3}	AFP	Appendix F: Book 9
	Closed Loop RHR Cooling Disabled	1.0	N/A	N/A
Recovery Actions	Failure to Recover Offsite Power Within One Hour	4.7×10^{-1}	ORJ	Chapter 15.6
	Failure to Recover at Least One Failed Diesel Generator Within One Hour	8.4×10^{-1}	OMA	Chapter 15.6
	Total Sequence Frequency	1.4×10^{-6}		

Appendix 2: Table 3.6-1 (Cont.)
Additional Analysis of Top-Ranking Sequences for Mean Core Damage Frequency
(Sequence 18)

Sequence Element	Event Description	Mean Frequency (per year)	Split Fraction Identifier	Reference (PSA)
Initiating Event	Loss of Offsite Power	9.0×10^{-2}	LOSP	Chapter 7.6
System Failures Following	Diesel Generators B and C	1.9×10^{-2}	G2	Appendix F: Book 1
Initiating Event	Turbine Driven Train D and Motor Driven Train A Auxiliary Feedwater Pumps	1.9×10^{-2}	AFQ	Appendix F: Book 9
	Closed Loop RHR Cooling Disabled	1.0	N/A	N/A
Recovery Actions	Failure to Recover Offsite Power Within One Hour	4.7×10^{-1}	ORK	Chapter 15.6
	Failure to Recover at Least One Failed Diesel Generator Within One Hour	8.4×10^{-1}	OMB	Chapter 15.6
	Total Sequence Frequency	1.4×10^{-6}		

Appendix 2: Table 3.6-1 (Cont.)
Additional Analysis of Top-Ranking Sequences for Mean Core Damage Frequency
(Sequence 19)

Sequence Element	Event Description	Mean Frequency (per year)	Split Fraction Identifier	Reference (PSA)
Initiating Event	Loss of Offsite Power	9.0×10^{-2}	LOSP	Chapter 7.6
System Failures Following Initiating Event	Essential Cooling Water Train B (Hence Diesel Generator Train B)	1.3×10^{-1}	WBC	Appendix F: Book 1
	Turbine Driven Auxiliary Feedwater Pump D and Motor Driven Pump C	3.8×10^{-4}	AFO	Appendix F: Book 9
Recovery Actions	Failure to Recover Offsite Power Within One Hour	4.7×10^{-1}	ORI	Chapter 15.6
	Total Sequence Frequency	1.1×10^{-6}		

Appendix 2: Table 3.6-1 (Cont.)
Additional Analysis of Top-Ranking Sequences for Mean Core Damage Frequency
(Sequence 20)

Sequence Element	Event Description	Mean Frequency (per year)	Split Fraction Identifier	Reference (PSA)
Initiating Event	Steam Generator Tube Rupture	2.8×10^{-2}	SGTR	Chapter 7.6
System Failures	None	N/A	N/A	N/A
Recovery Actions	Failure to Isolate Stuck Open PORV or Safety Valve on Affected Steam Generator	2.4×10^{-2}	SLA	Appendix F: Book 8
	Failure to Align Plant for Closed Loop Cooling	2.6×10^{-3}	OCA	Appendix F: Book 17
	Total Sequence Frequency	1.1×10^{-6}		

Appendix 2: Table 3.6-1 (Cont.)
Additional Analysis of Top-Ranking Sequences for Mean Core Damage Frequency
(Sequence 21)

Sequence Element	Event Description	Mean Frequency (per year)	Split Fraction Identifier	Reference (PSA)
Initiating Event	Reactor Trip	$1.4 \times 10^{+0}$	RT	Chapter 7.6
System Failures Following Initiating Event	All Four Auxiliary Feedwater Trains	3.4×10^{-5} 7.8×10^{-1}	CDA AFA	Appendix F: Book 9
Recovery Actions	Failure to Start Bleed and Feed Cooling Through Both Pressurizer PORVs	4.8×10^{-2}	OBA	Chapter 15.4
	Failure to Recover Auxiliary Feedwater Flow Before the Steam Generators Dryout	1.0	N/A	N/A
	Total Sequence Frequency	1.1×10^{-6}		

Appendix 3: HLP Responses to Issues Raised During this Review

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Appendix 3: HLP Responses to Issues Raised During this Review

Table of Contents (Cont.)

Appendix 3: HLP Responses to Issues Raised During this Review

PP1: The time to steam generator dryout following loss of all feedwater is not fully justified. (Section 2.1.1 of this report)

Response:

A reanalysis was performed by HL&P which resulted in a reduced steam generator dryout time and provided justification for its applicability to the current South Texas Project Probabilistic Safety Assessment (PSA). This information was transmitted on March 1, 1990 via a letter to the NRC, ST-HL-AE-3380. This analysis shows that even for a reduced steam generator dryout time of approximately 34 minutes, no impact on the likelihood of the operators to initiate bleed and feed primary side cooling will result.

Appendix 3: HLP Responses to Issues Raised During this Review

PP2: The ability of equipment in the ECCS pump rooms to operate without forced cooling to the rooms is not fully justified. (Section 2.2.3 of this report)

Response:

Studies have been performed which show that the equipment in the ECCS pump rooms can be expected to operate up to three days without forced room cooling.

HL&P has performed a calculation (EQ-89-001) which extends the qualified life of equipment and cables in the FHB ECCS cubicles beyond the normal, abnormal, and accident service time to accommodate temperatures of 200°F for 7.4 days. There are no electrical or control components in the rooms which could affect the operation of the pumps or valves.

Two transient heatup studies have been performed (correspondence ST-3R-HS-00804 dated November 17, 1989 and ST-3R-HS-00895 dated January 3, 1990 from Bechtel to HL&P). These studies conclude that without forced room cooling, and without taking credit for natural convection between the ECCS pump room and the remainder of the FHB (which is a conservative assumption given the layout of the ECCS pump cubicles), the temperature in the ECCS cubicles is under 200°F at a termination time of 3 days. This is well beyond the PSA analyzed mission time of twenty-four (24) hours.

PP3: The confusion regarding labeling split fractions AFP, AFQ, and AFO in the dominant sequences (Table 3.6-1) should be resolved. (Section 3.6 of this report)

Response:

HL&P reviewed the five dominant sequences identified in Section 3.6 of the Sandia report where a discrepancy in AFW split fraction assignment was identified. Correction of the discrepancy does not effect the PSA calculated core damage frequency (CDF) of 1.7E-4 events per year. To address this issue, some introductory information on AFW system modeling is first needed.

The AFW system includes four pump trains: three motor driven (Trains A, B, and C) and one steam turbine driven (Train D). The motor driven pump trains are identical. The technical specifications allow Trains B, C, and D to be out of service for up to 72 hours and require Train A to be repaired "as soon as possible". The technical specifications also allow any combination of two trains to be out of service for up to 72 hours. As a result, the PSA divides the four trains into three groups based on their calculated unavailability. First, Trains B and C are identical motor driven pump trains that are limited to only 72 hours for being out of service. Second, Train A can be out of service indefinitely as long as the repair is being actively pursued (e.g., a long lead time for replacement parts), thus it is represented with the appropriate maintenance duration. Third, Train D is a turbine driven pump train that has different characteristics than the three motor driven trains. These characteristics include turbine driven pump maintenance frequency and additional steam supply valves.

Although Train A has the same equipment and testing requirements as Trains B and C, its extended maintenance contribution allowed by the technical specifications makes it less available. A conservative assumption used in assigning split fractions in the PSA event trees is that Train A unavailability is used to model at least one of the available motor driven pump trains. For example, if the EDG supplying AC power to Train B equipment is all that is available for a LOSP initiating event, then the split fraction representing Trains A and D is used, instead of Trains B and D. Note that Train D is steam driven and does not require AC power.

For Sequences 10 and 17 in Table 3.6-1, the failure of AFW Trains C and D is conservatively modeled by split fraction AFP because Train A's maintenance unavailability contributor is greater than Train C's.

For Sequence 14 in Table 3.6-1, the failure of AFW Trains B and D is conservatively modeled by split fraction AFP because Train A's maintenance unavailability contributor is greater than Train B's.

For Sequence 19 in Table 3.6-1, the event description is incorrect. The event description should identify that Trains A, C, and D are available, but fail to supply makeup to their corresponding steam generator. Split fraction AFO represents the likelihood of two motor-driven (i.e., Trains A and B or A and C) and the one turbine-driven (i.e., Train D) AFW pump trains will fail. As a result, the assignment of AFO and the frequency associated with this sequence is correct.

For Sequence 18 in Table 3.6-1, the split fraction assignment is not correct. Split fraction AFQ represents the likelihood of two motor-driven (i.e., Trains A and B or A and C) AFW pump trains will fail. The correct split fraction for the failure of AFW Trains A and D is AFP, which is a factor of 1.92 (AFP/AFQ = 4.888E-3/2.544E-3) greater than AFQ because of the difference between a motor-driven and turbine-driven pump train unavailability. As a result of using split fraction AFP instead of AFQ, the sequence ranking will rise to the number six position with a frequency of approximately 2.69E-6.

A review of the top 100 sequences was made to ensure that the correct AFW split fraction assignments were made. The result of that review identified another example of using split fraction AFQ instead of AFP. This example would raise Sequence 33 to the nineteenth (19) position with a frequency of 1.34E-6. Sequence 33 is similar to Sequence 18, but with one EDG and another ECW pump train being unavailable which represents two EDGs unavailable. Although the impact on both of these sequences is noted, no change in the published CDF of 1.7E-4 results.

During the next update of the PSA, the split fraction misassignment will be addressed and corrected. It is anticipated that a change in the event tree split fraction assignments will correct this problem.

Appendix 3: HLP Responses to Issues Raised During this Review

IE1: Quantification of the PTS split fraction is not clearly provided. (Section 2.1.1 of this report)

Response:

The vessel integrity split fraction VIA evaluates the failure probability of the reactor vessel after a pressurized thermal shock (PTS) challenge. PTS is the term used to describe an event in a PWR that produces a severe overcooling of the inside surface of the reactor vessel wall, concurrent with or followed by repressurization. The PSA transient event tree models the potential PTS challenge when the reactor trips, but the turbine fails to trip and the MSIVs fail to close; that is, severe secondary depressurization event. The value of 1.1E-4 used for split fraction VIA (vessel integrity after a PTS challenge) in the PSA event tree model quantifications was taken from the result of an evaluation of the failure probability of the reactor vessel under a similar condition in the Diablo Canyon PRA (See Appendix A, DCPRA report, DCPRA-PLG-409). This was judged to be conservative since the STPEGS Unit 1 reactor vessel is expected to be able to better withstand a PTS challenge than the Diablo Canyon Unit 2 reactor vessel because the copper content of the STPEGS Unit 1 vessel components which are important to PTS failure is in the range of approximately 0.03 to 0.07% (see the STPEGS UFSAR Table 5.3-3), which is much lower than that of the Diablo Canyon Unit 2 vessel material (0.14 to 0.15%). The copper content in the vessel material directly influences the value of the end-of-life RTPTS which is the reference temperature for nil ductility transition and is a measure of fracture toughness of the vessel material. The lower the value of the RTPTS, the greater the toughness of the material. The end-of-life RTPTS values for the Diablo Canyon Unit 2 vary from <185°F to 228°F which are much higher than those of STPEGS unit 1 vessel material which ranges from 5° to 93°F.

The PSA indicates that PTS is valid challenge for overcooling events, however the UFSAR (see below) indicates that PTS is not a concern at STPEGS. No details for the quantification of the PTS split fraction are provided in the PSA (as indicated in the Sandia comment).

Reference:

UFSAR Section 5.3.2. Using the Regulatory Guide 1.99 Rev. 1 "Predicted Adjustment of Reference Temperature" curve, the predicted adjusted reference temperature is less than 200°F. The limiting material for Unit 1 reactor vessel is the intermediate shell plate No. R-1606-3. The reactor vessel materials have properties of 0.05% Cu, 0.62% Ni and 10°F initial RTNDT. The estimated end of life RTPTS is equal to 88°F. The limiting material for Unit 2 reactor vessel is the intermediate shell plate No. R-2507-2. The reactor vessel materials have properties of 0.05% Cu, 0.64% Ni and -10°F initial RTNDT. The estimated end of life RTPTS is equal to 68°F.

The above RTPTS values are well below the NRC screening criteria which is 270°F for plates, forgings, and axial welds, and 300°F for circumferential welds.

Lastly, the plant Emergency Operating Procedures include guidance for the operators to limit challenges to the vessel from the injection of cold water from the RWST. (cold leg temperature decrease > 100°F in last 60 minutes AND RCS cold leg temperature < 244°F). This would indicate that overcooling from unisolated steam generators may not be a concern.

Appendix 3: HLP Responses to Issues Raised During this Review

IE2: The use of the nomenclature "hot standby" and "hot shutdown" are inconsistent with the definitions in the Technical Specifications. (Section 2.1.1 of this report)

Response:

Inconsistencies in the use of "hot standby" and "hot shutdown" are identified below. The definitions in the plant Technical Specifications are as follows:

Mode	Definition
1	Power Operation
2	Startup
3	Hot Standby (greater than or equal to 350°F)
4	Hot Shutdown (350°F > Tavg > 200°F)
5	Cold Shutdown
6	Refueling

Consistent with these definitions, the following clarifications are made:

Page 5.4-27 - should be hot standby (Event 70). This will be changed from hot shutdown.

Page 5.4-29 - should be hot shutdown (4th paragraph) as indicated for the description.

Page 5.4-33 - should be hot standby (Top Events CD and AF). This will be changed from hot shutdown.

Page 5.4-34 - should be hot standby (Top Event S2). This will be changed from hot shutdown.

Page 5.4-37 - should be hot standby (Top Event ON). This will be changed from hot shutdown.

Table 5.4-4 - should be hot standby. This will be changed from hot shutdown.

The above clarifications do not impact the PSA analysis, they only correct inconsistencies in the use of the terms "hot standby" and "hot shutdown." These inconsistencies will be corrected in the next update of the PSA.

Appendix 3: HLP Responses to Issues Raised During this Review

IE3: Accumulator injection following large or medium LOCAs is assumed to not be required. This assumption is not justified. (Sections 2.1.2 and 2.1.3 of this report)

Response:

As discussed in the November 1989 meeting between HL&P, SNL and the NRC, HL&P has already committed to include the accumulators in the plant model for the Level II (i.e., IPE Back End) analysis.

For Medium LOCAs (2 to 6 inch), the HHSI pumps will be operating and reflooding the RPV prior to reaching 600 psi. The accumulators will aid in refilling the RPV for these breaks and slow down RCS depressurization to the LHSI shutoff head. UFSAR Chapter 15 analysis for 6 in. and 3 in. breaks (see attachments) indicate that vessel water level is above the active core prior to accumulator injection. For the 4 in. break, vessel level is recovering prior to accumulator injection (approximately 1000 seconds). See attached figures from the STPEGS UFSAR. Question 211.84 (UFSAR Response to NRC Questions) indicates that for the 4 in. break, HHSI flow matches break flow at 950 seconds and core mixture level is increasing with one HHSI train injecting into the vessel.

The accumulator system has been quantified using RISKMAN as part of the plant model update. With the assumption that two (2) accumulators injecting into intact RCS loops are required for success in the Large LOCA initiating event, the system unavailability is approximately 2.2E-03. From the PSA, the Large LOCA initiating event frequency is 2.0E-04 events per reactor year. The likelihood of core damage due to accumulator failure after a Large LOCA initiating event is:

CDF = LLOCA x Accumulator Failure
CDF = 2.0E-04 x 2.2E-03 = 4.4E-07 / reactor year.

This frequency is considered negligible in relation to other causes of core damage.

TABLE 15.6-8

SMALL BREAK
TIME SEQUENCE OF EVENTS

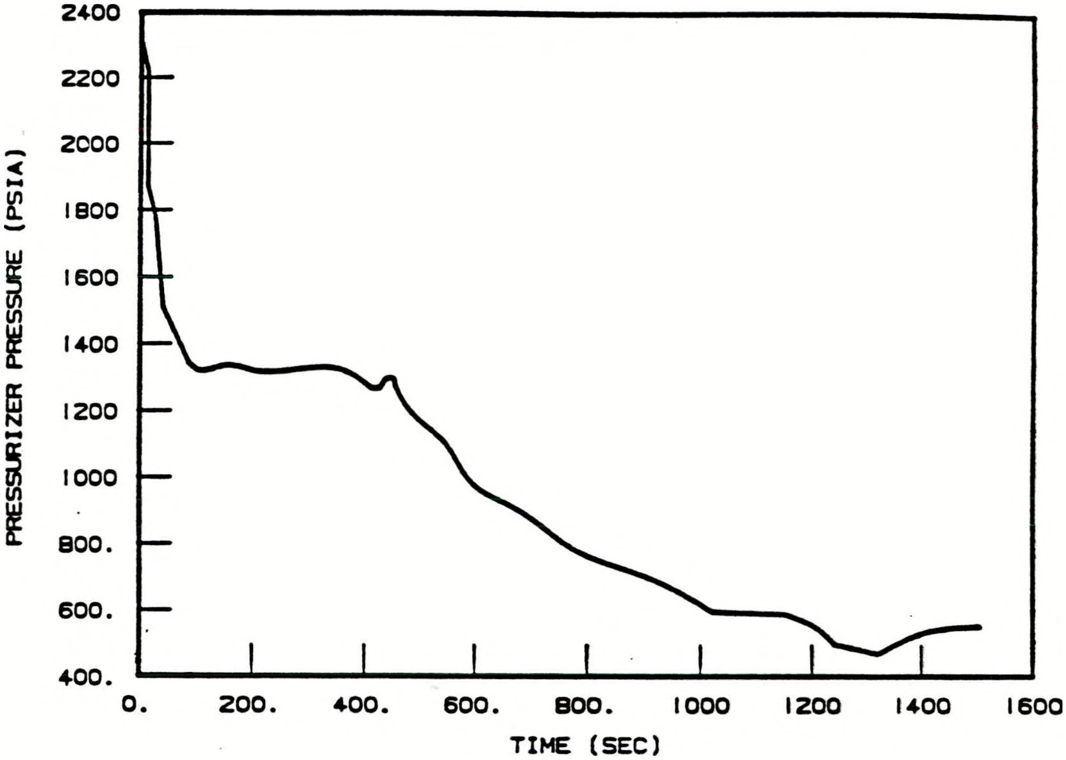
	Times (second)		
	6 in.	4 in.	3 in.
Start (Accident Initiation)	0.0	0.0	0.0
Reactor Trip Signal, sec	3.716	9.178	15.844
Top of Core Uncovered, sec	164.33	370.28	639.10
Accumulator Injection Begins, sec	424.45	1,057.18	N/A
Peak Clad Temp. Occurs, sec	197.89	885.86	701.67
Top of Core Covered, sec	214.92	1,195.17	715.02

TABLE 15.6-9

SMALL BREAK RESULTS

	6 in.	4 in.	3 in.
Peak Clad Temp., °F	950.55	1,366.45*	1,030.25
Peak Clad Location, ft	13.0	14.0	13.0
Local Zr/H_2O Reaction, max %	0.0361	0.2816	0.0366
Local Zr/H_2O Reaction Location, ft	13.0	14.0	13.0
Total Zr/H_2O Reaction, %	<0.3	<0.3	<0.3
Hot Rod Burst Time, sec	N/A	N/A	N/A
Hot Rod Burst Location, ft	N/A	N/A	N/A

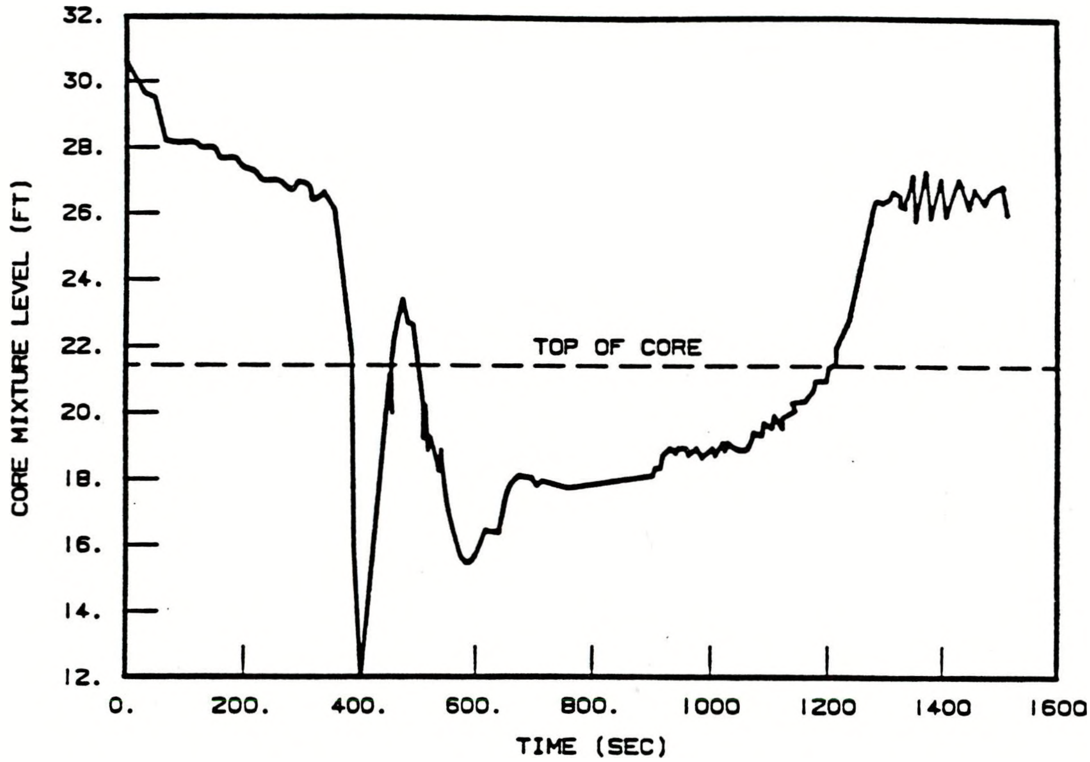
* Test data reflecting reduced safety injection flow rates and the associated sensitivity analyses may increase this peak clad temperature value to approximately 1,407°F. This value continues to maintain considerable margin (approximately 790°F) to the limit of 10CFR50.46.



SOUTH TEXAS PROJECT UNITS 1 & 2

RCS DEPRESSURIZATION TRANSIENT (4-INCH BREAK)

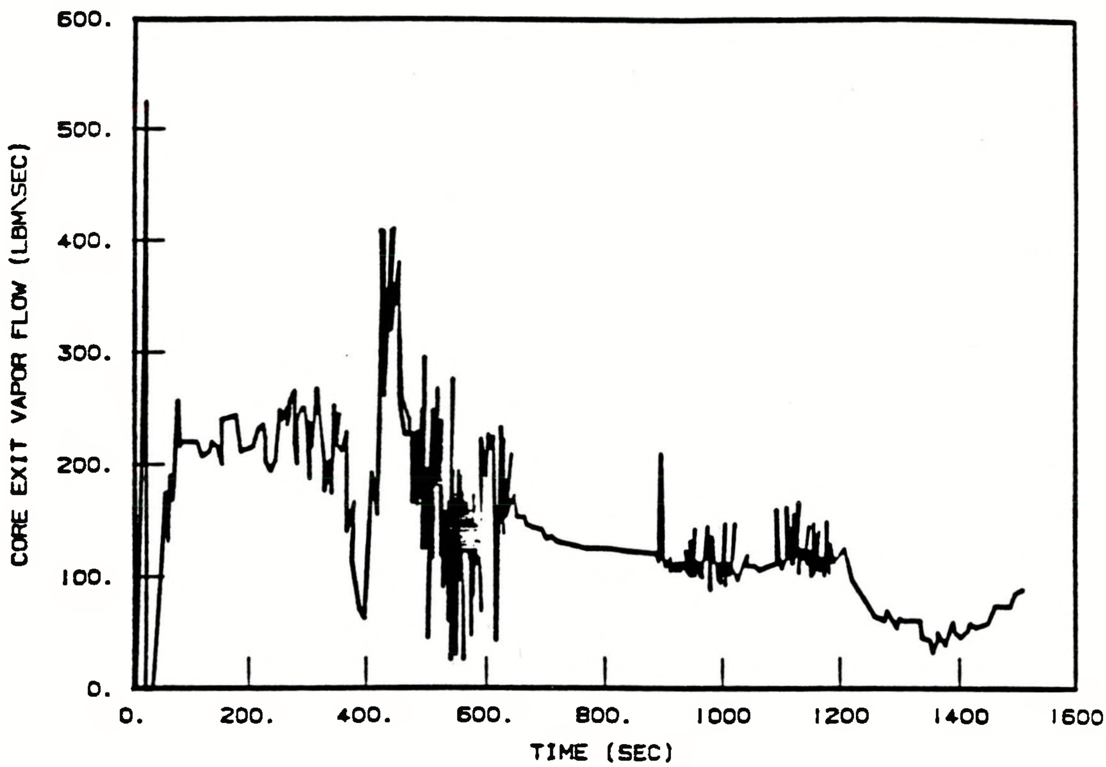
Figure 15.6-41 **Revision 0**



SOUTH TEXAS PROJECT UNITS 1 & 2

CORE MIXTURE HEIGHT (4-INCH BREAK)

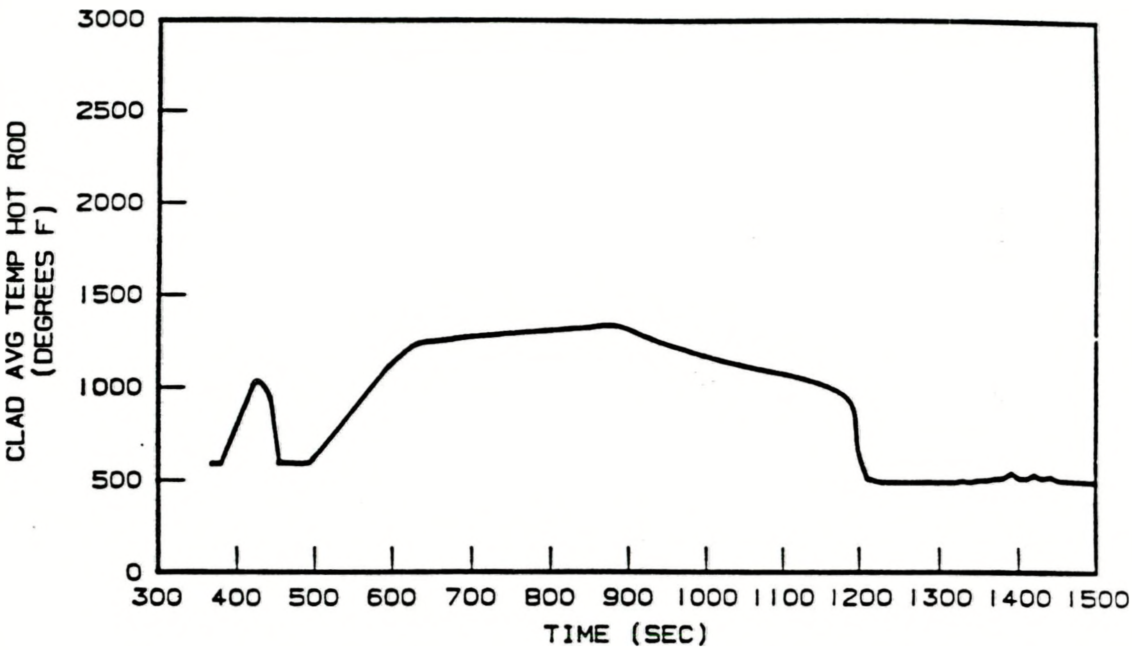
Figure 15.6-42 **Revision 0**



SOUTH TEXAS PROJECT
UNITS 1 & 2

STEAM FLOW
(4-INCH BREAK)

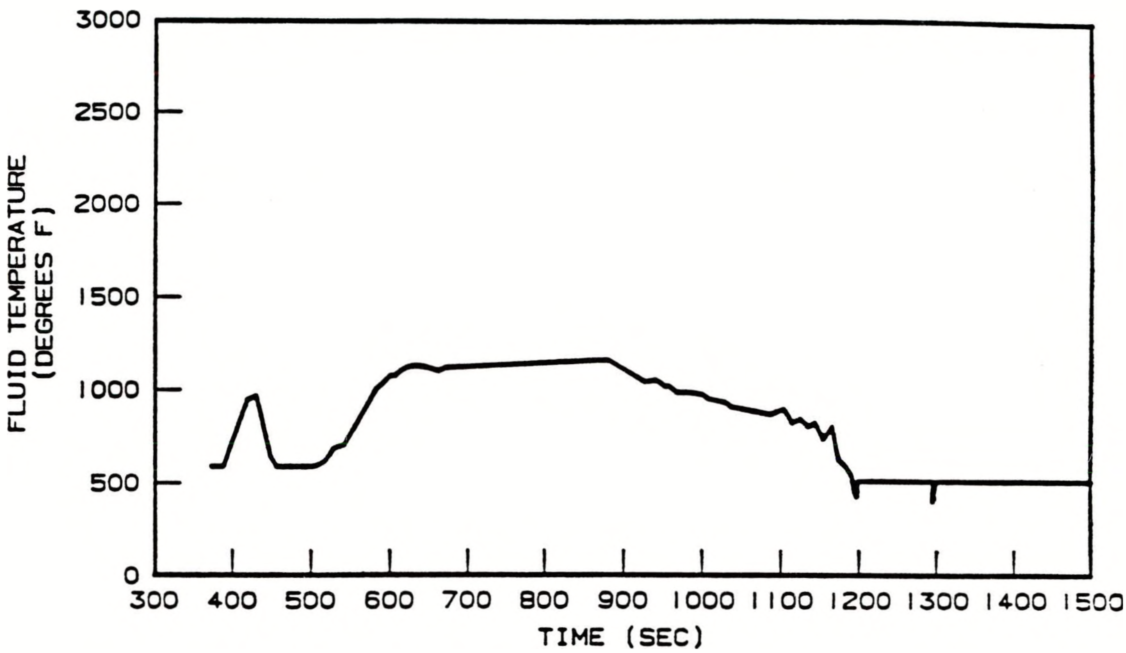
Figure 15.6-43 **Revision 0**



SOUTH TEXAS PROJECT
UNITS 1 & 2

CLAD TEMPERATURE TRANSIENT
(4-INCH BREAK)

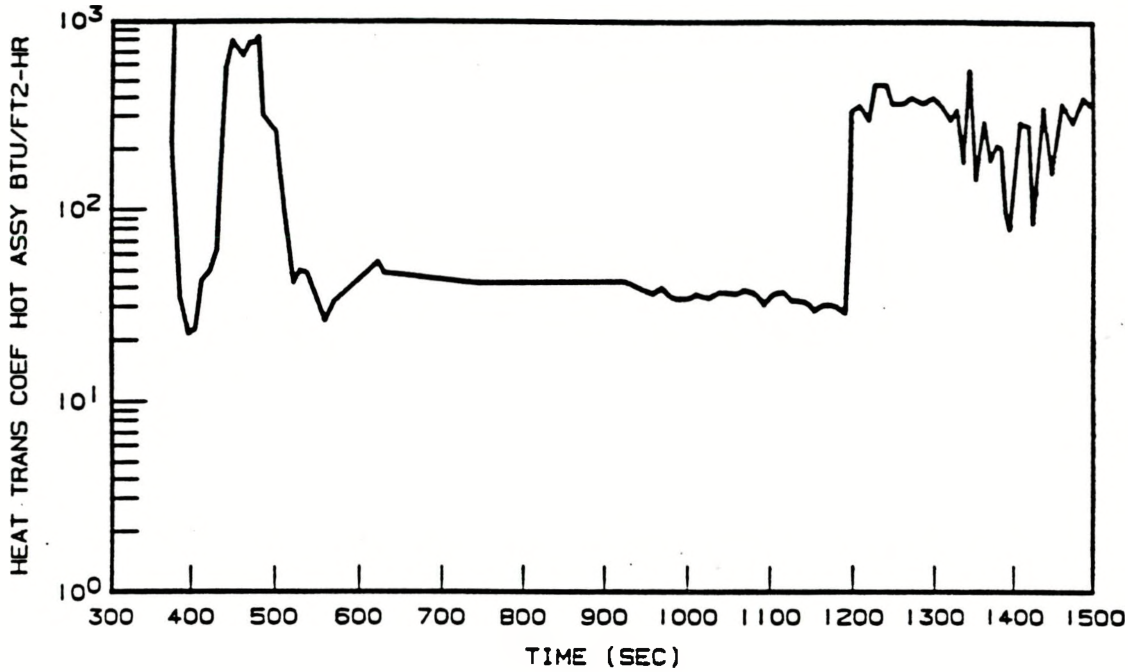
Figure 15.6-44 Revision 0



SOUTH TEXAS PROJECT
UNITS 1 & 2

HOT SPOT FLUID TEMPERATURE
(4-INCH BREAK)

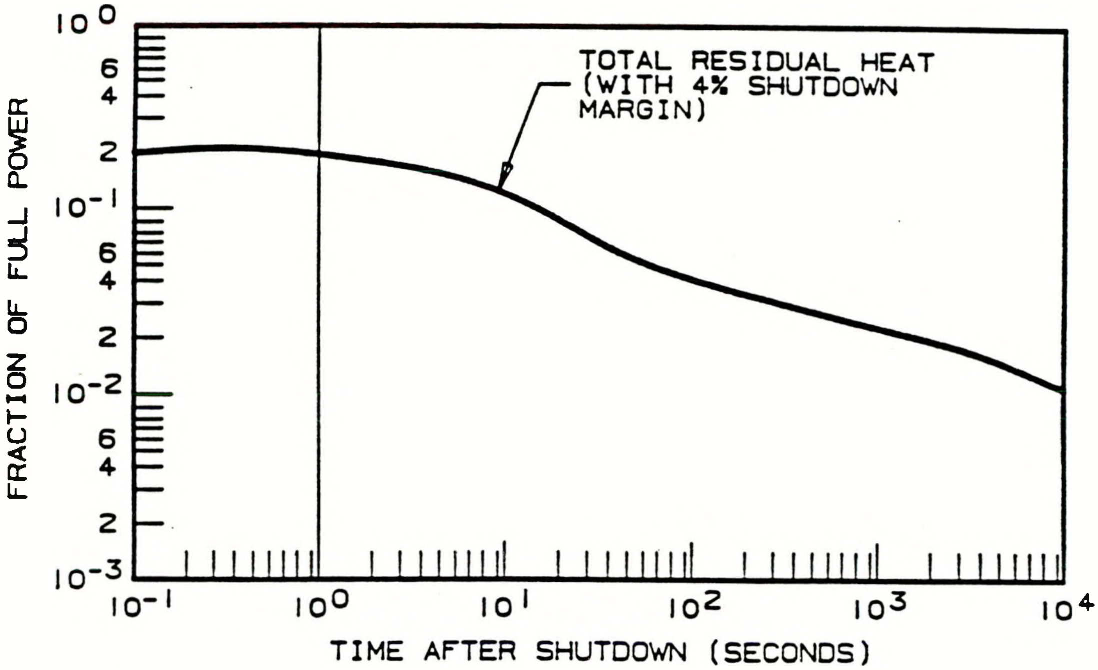
Figure 15.6-45 **Revision 0**



SOUTH TEXAS PROJECT
UNITS 1 & 2

ROD FILM HEAT TRANSFER COEFFICIENT
(4-INCH BREAK)

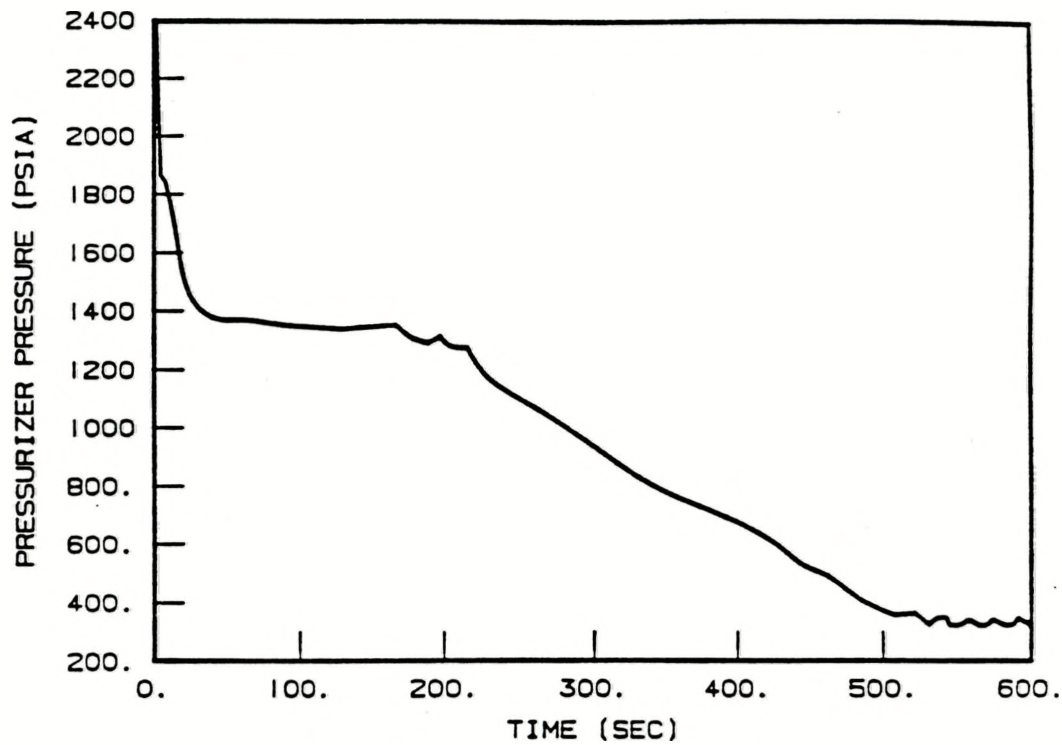
Figure 15.6-46 **Revision 0**



SOUTH TEXAS PROJECT
UNITS 1 & 2

CORE POWER AFTER REACTOR TRIP (4, 6, & 3-INCH BREAK)

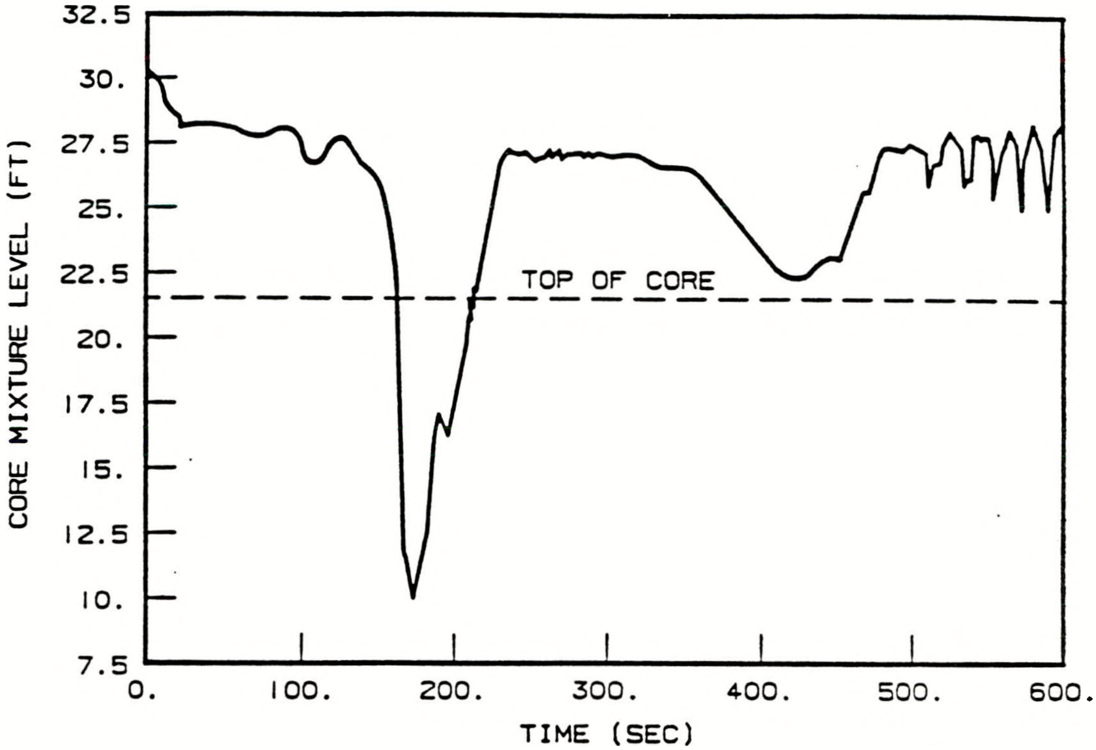
Figure 15.6-47 Revision 0



SOUTH TEXAS PROJECT UNITS 1 & 2

RCS DEPRESSURIZATION TRANSIENT

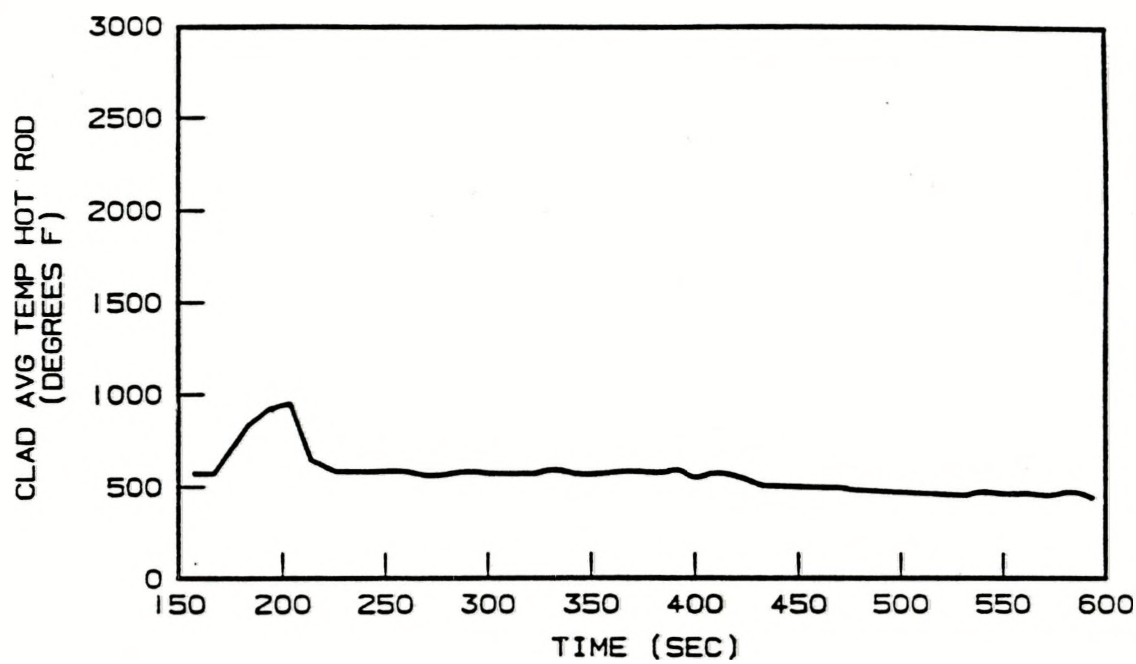
Figure 15.6-48 **Revision 0**



SOUTH TEXAS PROJECT
UNITS 1 & 2

CORE MIXTURE HEIGHT
(6-INCH BREAK)

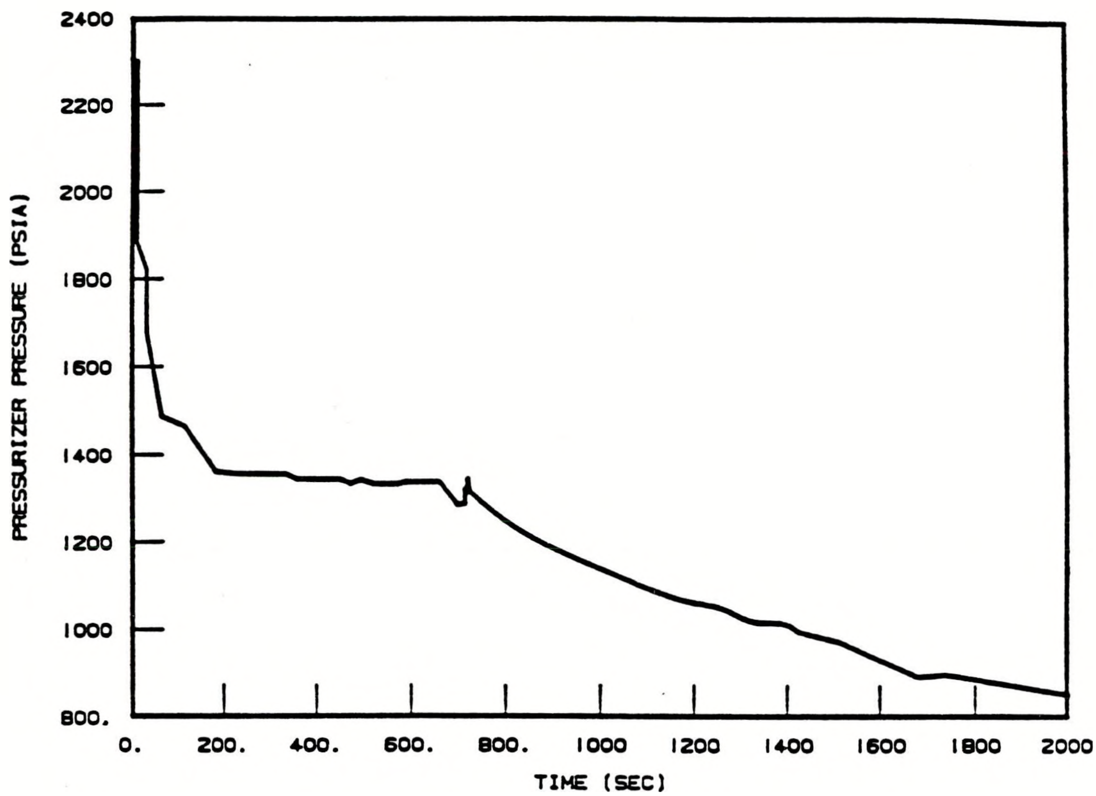
Figure 15.6-49 **Revision 0**



SOUTH TEXAS PROJECT UNITS 1 & 2

CLAD TEMPERATURE TRANSIENT (6-INCH BREAK)

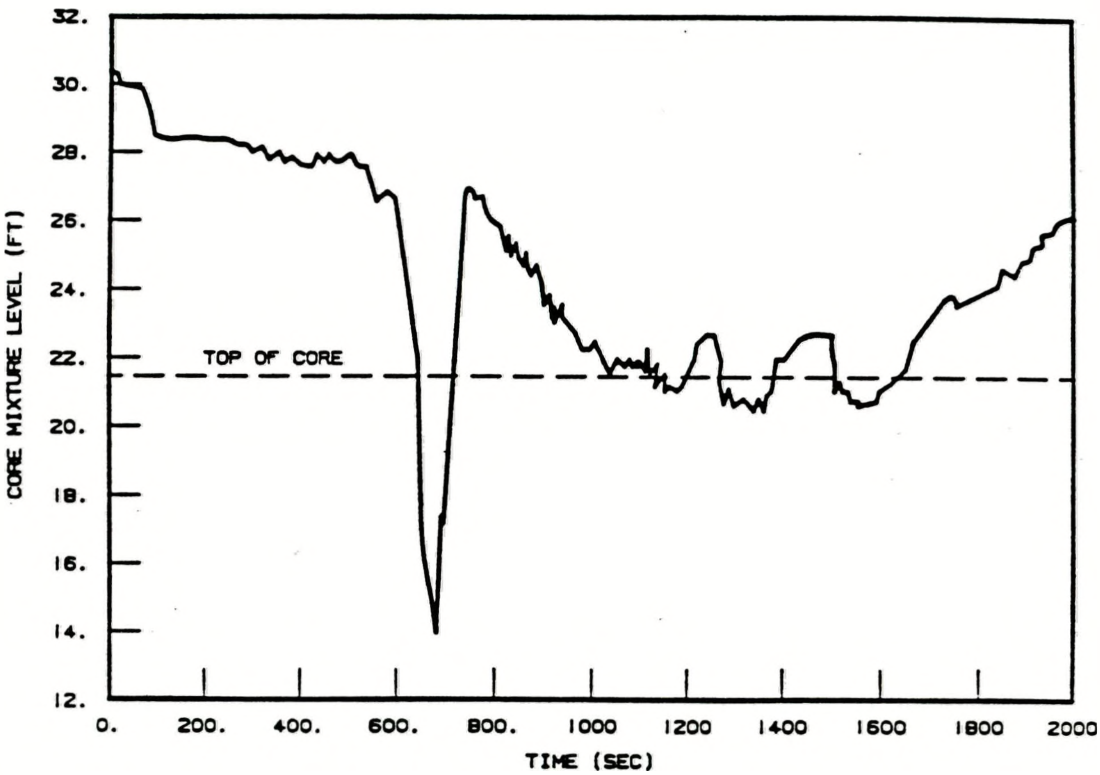
Figure 15.6-50 **Revision 0**



SOUTH TEXAS PROJECT
UNITS 1 & 2

RCS DEPRESSURIZATION TRANSIENT
(3-INCH BREAK)

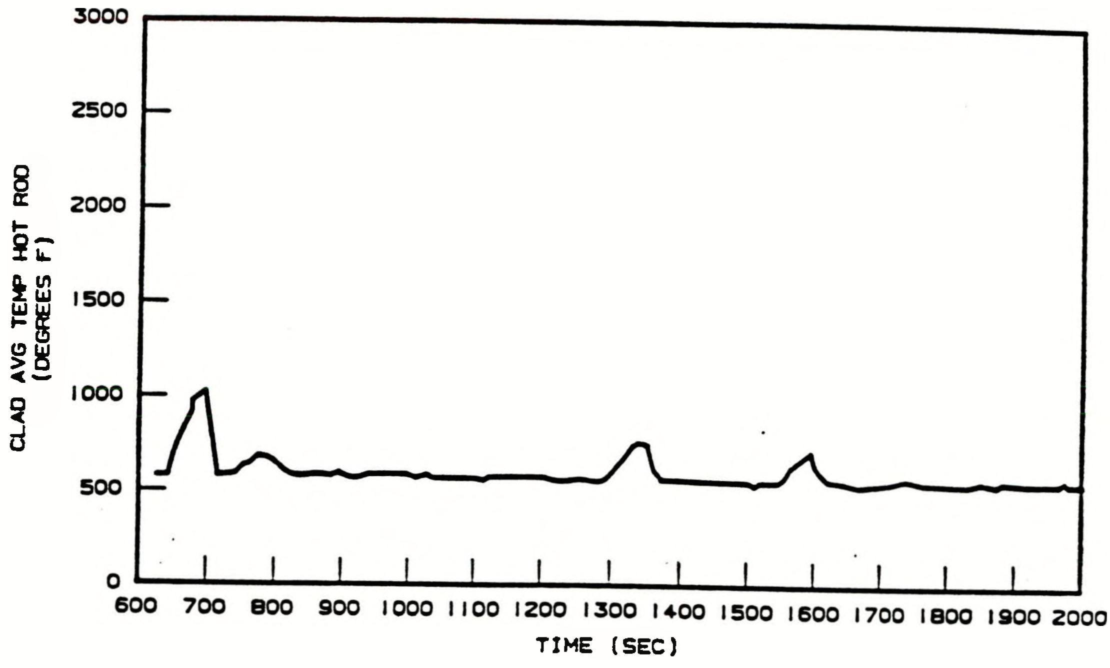
Figure 15.6-51 **Revision 0**



SOUTH TEXAS PROJECT
UNITS 1 & 2

CORE MIXTURE HEIGHT
(3-INCH BREAK)

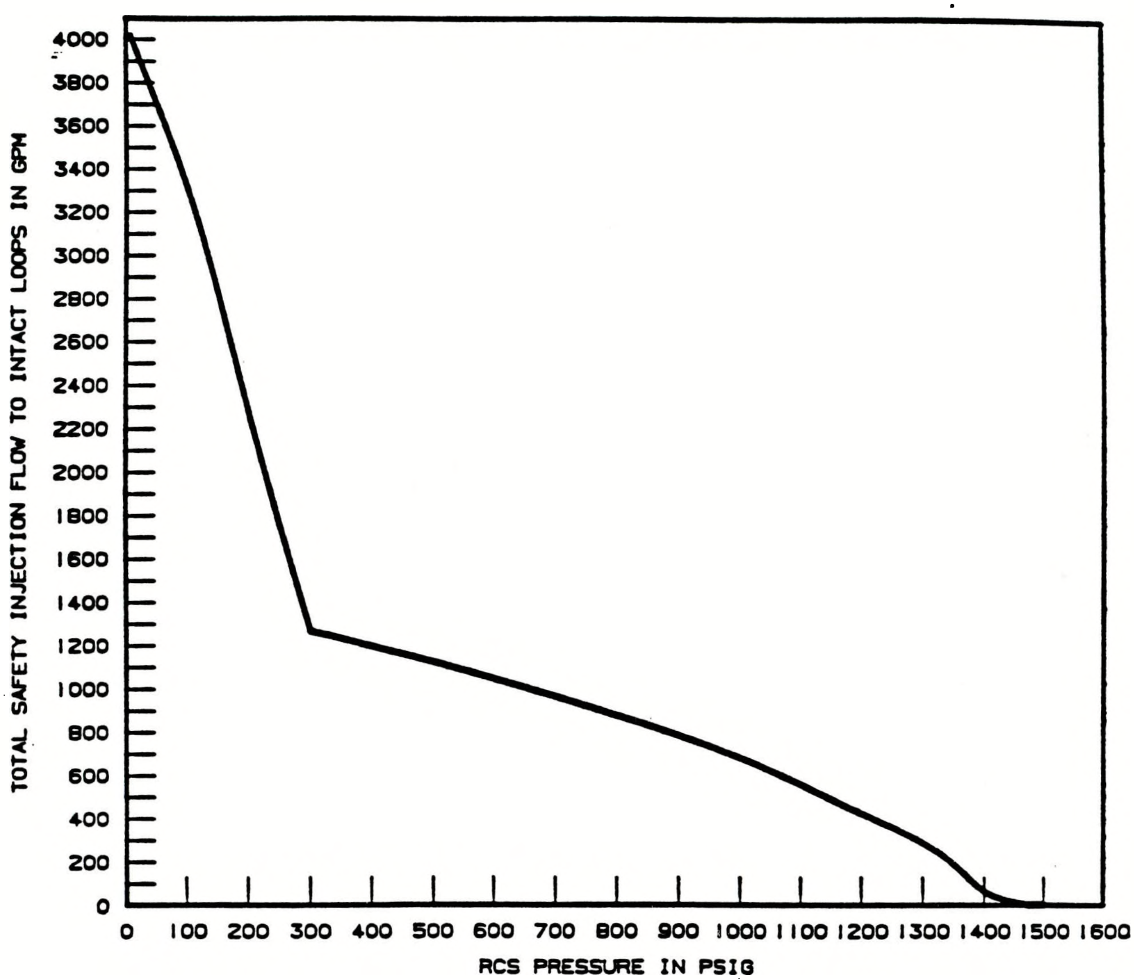
Figure 15.6-52 Revision 0



**SOUTH TEXAS PROJECT
UNITS 1 & 2**

**CLAD TEMPERATURE TRANSIENT
(3-INCH BREAK)**

Figure 15.6-53 **Revision 0**



SOUTH TEXAS PROJECT
UNITS 1 & 2

TGX SMALL BREAK SAFETY INJECTION FLOW RATE VERSUS RCS PRESSURE

Figure 15.6-54 Revision 0

Appendix 3: HLP Responses to Issues Raised During this Review

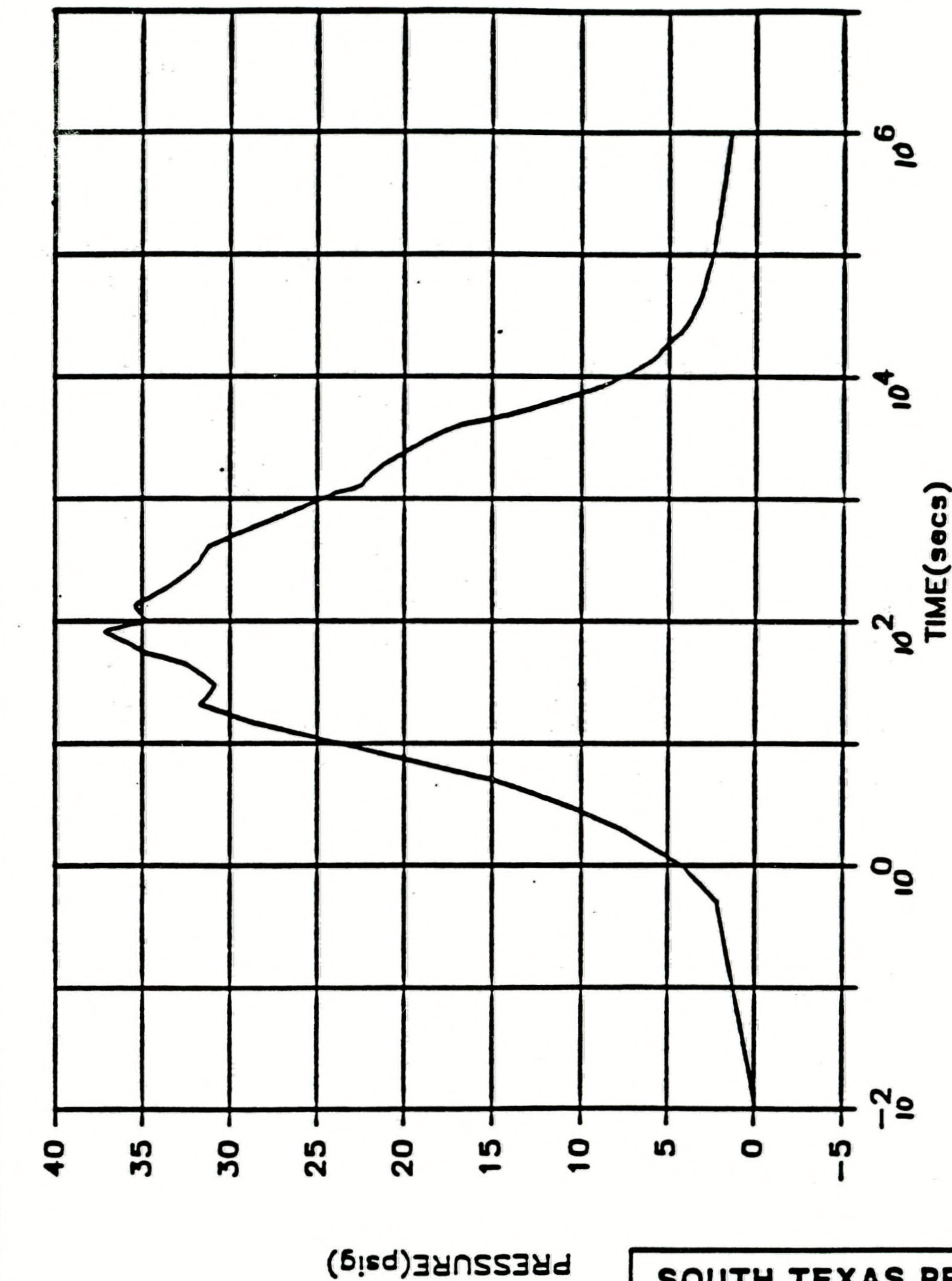
IE4: The effect of early failure to isolate containment on reflood, following a large LOCA, is not addressed. (Section 2.1.2 of this report)

Response:

Failure to isolate containment following a large LOCA is considered to impact the core reflood rate, but not result in significant fuel clad damage. This conclusion is based on the discussion presented below.

The UFSAR Chapter 15.6 describes the analyses performed for the design basis large LOCA. The LOCA analyses account for containment pressure in assisting the core reflooding rate during the reflood phase (i.e., the higher the containment pressure, the faster the reflood). The rate of reflooding affects the calculated Peak Clad Temperature (PCT). Westinghouse has identified that a conservative estimate for the effects of a change in containment pressure is 50°F of PCT for 0.5 psi of containment pressure. The limiting break in terms of PCT is the double ended cold leg guillotine break with a discharge coefficient of 0.6 and maximum SI flow (from UFSAR Table 15.6-7). UFSAR Figure 15.6-26 presents a plot of PCT and UFSAR. Figure 15.6-31 presents a plot of the containment pressure for the limiting large LOCA. The large LOCA analysis in Chapter 15.6 assumes that the 18 in. supplemental purge lines are open at the start of the event and are isolated at 23 seconds into the event. From Figure 15.6-26, PCT occurs at approximately 130 seconds with a containment pressure of 8 psig. Assuming that the supplemental purge lines remain open throughout the LOCA transient, the rate of containment depressurization will be greater than that presented in UFSAR Figure 15.6-31.

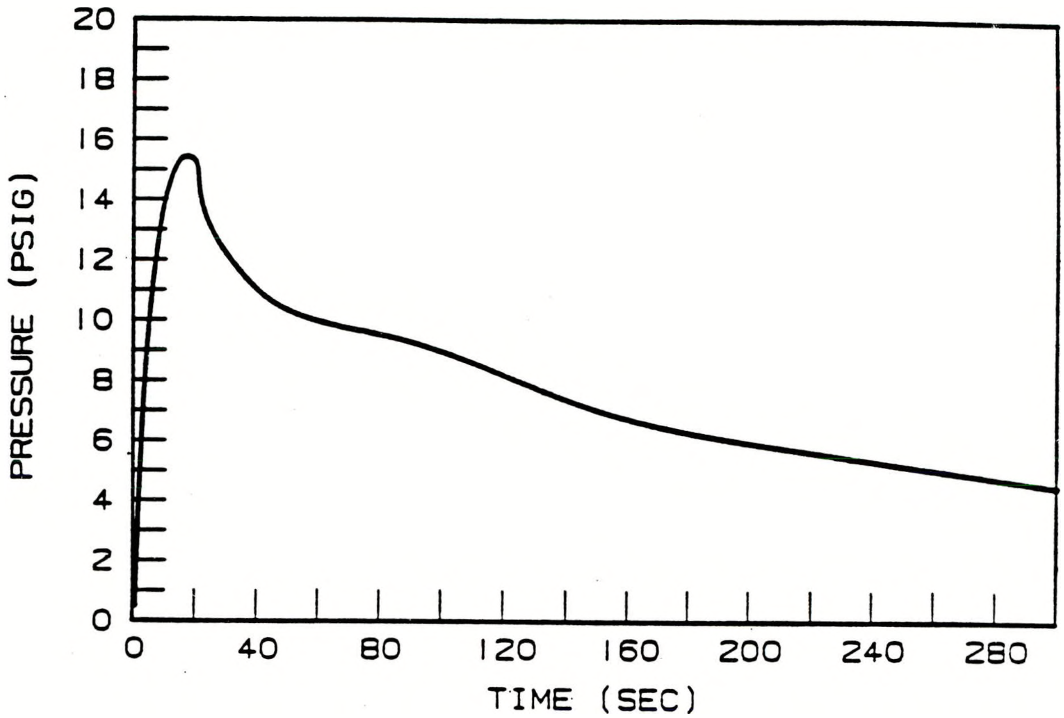
A conservative estimate for the pressure loss through the two supplemental purge lines results in an additional decrease in containment pressure of 3.8 psi. This is equivalent to an increase in PCT of 380°F using the vendor rule of thumb presented above. This increases the PCT to less than 2510°F. This temperature is above the PCT limit of 2200°F for the UFSAR LOCA analyses but below the zirconium phase transition temperature of 2900°F. Staying below the zirconium phase transition temperature ensures no clad melting and no significant increase in the clad oxidation rate. Therefore, in terms of the PSA success criteria, no core damage occurs if the supplemental purge lines remain unisolated for a Large LOCA.



SOUTH TEXAS PROJECT
UNITS 1 & 2

LOCA-2 CONTAINMENT PRESSURE

Figure 6.2.1.1-5 **Revision 0**



SOUTH TEXAS PROJECT
UNITS 1 & 2

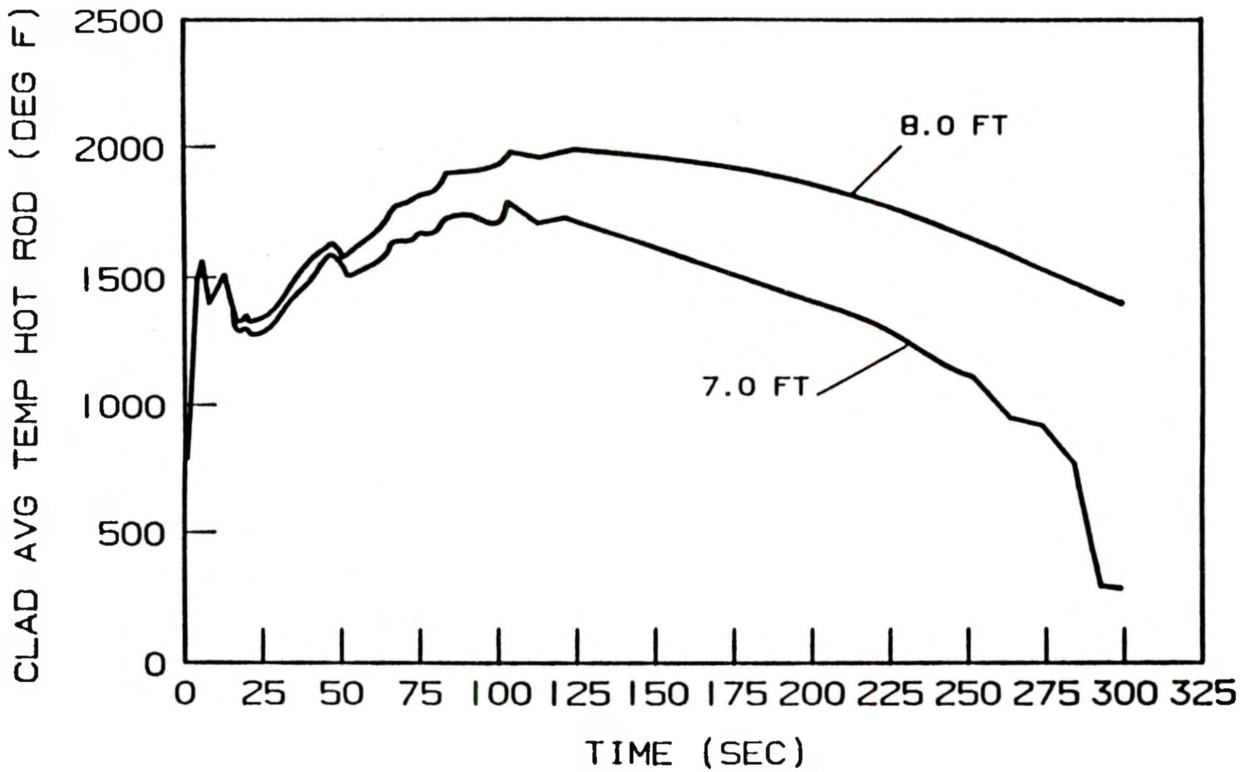
TGX Large-Break LOCA Analysis
DECLG, C_D = 0.6 (Max.SI)
Containment Backpressure

Figure 6.2.1.5-1 **Revision 0**

TABLE 15.6-7

LARGE BREAK ANALYSIS RESULTS

	DECLG C_D=0.4 (Min SI)	DECLG C_D=0.6 (Min SI)	DECLG C_D=0.8 (Min SI)	DECLG C_D=0.6 (Max SI)
Peak clad temperature, °F	1,685	1,991	1,973	2,127
Elevation, ft	7.75	8.00	8.00	8.00
Max. local Zr/H_2O reaction, %	2.06	4.45	5.64	4.94
Elevation, ft	8.00	7.75	7.75	8.00
Total Zr/H_2O reaction, %	<0.3	<0.3	<0.3	<0.3
Hot rod burst time, sec	103.4	45.6	60.2	45.4
Elevation, ft	8.00	7.00	7.75	7.00

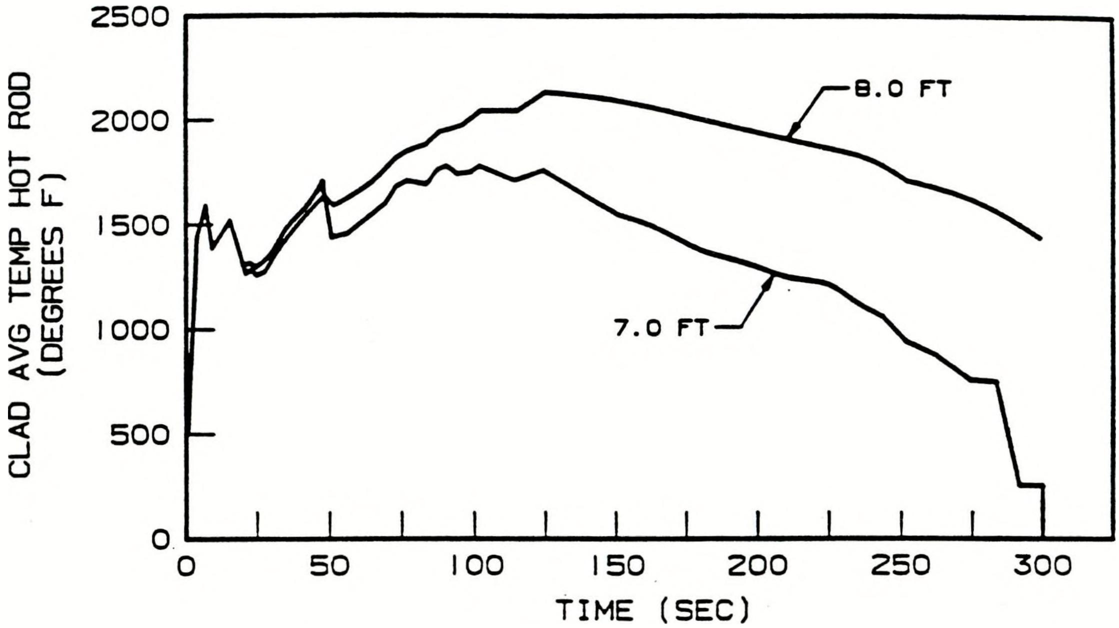


SOUTH TEXAS PROJECT UNITS 1 & 2

Peak Clad Temperature
DECLG,CD = 0.6

Figure 15.6-14

Revision 0



SOUTH TEXAS PROJECT UNITS 1 & 2

Peak Clad Temperature
DECLG, C_D = 0.6 (Max. SI)

Figure 15.6-26 Revision 0

TABLE 6.2.1.1-11

COMPARATIVE RESULTS: SUMMARY OF RESULTS OF CONTAINMENT
PRESSURE AND TEMPERATURE ANALYSIS FOR THE SPECTRUM OF POSTULATED ACCIDENTS

Accident	1	2	3	4	5	6
Break location	Pump suction (PS)	PS	Hot leg	Cold leg	PS	PS
Break type	Double-ended guillotine (DEG)	DEG	DEG	DEG	0.6 DEG	Split
Break size	10.48 ft^2	10.48 ft^2	9.18 ft^2	8.24 ft^2	6.24 ft^2	3.00 ft^2
Safety injection	min	max	max	max	max	max
Containment Heat Removal System (CHRS)	min	min	min	min	min	min
Peak pressure, psig	37.4	37.5	36.8	30.5	36.8	36.0
Time to peak pressure, sec	82.6	82.6	39.3	16.05	82.6	82.6
Peak temperature, °F	307.0	307.5	282.0	268.6	305.6	295.0
Time to peak temperature, sec	82.6	82.6	39.3	82.6	82.6	82.6
Energy released to Containment at time of peak pressure, 10^6 Btu	451.1	452.48	434.62	340.31	444.57	436.66
Energy absorbed by passive heat sinks at time of peak pressure, 10^6 Btu	82.69	82.74	62.67	19.83	79.96	75.73
Energy in vapor region at time of peak pressure, 10^6 Btu	296.0	296.84	312.30	269.9	291.13	289.98
Energy in sump water at time to peak pressure, 10^6 Btu	98.10	98.48	77.4	69.1	99.04	94.96
Energy removed by Containment fan coolers up to the time of peak pressure, 10^6 Btu	3.21	3.21	0.0	0.0	3.06	2.72
Energy removed by containment sprays up to time of peak pressure, 10^6 Btu	0.0	0.0	0.0	0.0	0.0	0.0

Appendix 3: HLP Responses to Issues Raised During this Review

IE5: The need to switchover from cold leg to hot leg recirculation to avoid boron precipitation is not addressed. (Section 2.1.2 of this report)

Response:

Switchover from cold leg recirculation to hot leg recirculation to avoid boron precipitation is not included in the PSA since it was not considered as leading to core melt. If it were assumed to lead to core melt it is estimated that its contribution to CDF would be approximately 0.01% or less.

Reference:

ERG Background document ES-1.4 LP Rev. 1A July 1, 1987. This document discusses the need for switching to hot leg recirculation. The basis for the switch to hot leg recirculation is the design basis cold leg LOCA (by definition a Large LOCA in the PSA). The switch to hot leg recirculation is considered to be necessary, using conservative analyses, to limit the boron concentration increase that occurs in the RPV after the design basis cold leg break. Boron precipitation could reduce heat transfer from the fuel to the reactor coolant. The plant emergency procedures discuss the steps necessary to achieve hot leg recirculation (POP05-EO-ES14). Failure to shift to hot leg recirculation is not considered as leading to severe core damage in the PSA and was not included in the Large LOCA event tree. If the event were included, and if the assumption is made that failure to shift to hot leg recirculation leads to core damage, the frequency of core damage associated with this failure can be determined by multiplying the Large LOCA initiating event frequency (per year) by the operator failure frequency for this event. From the PSA, the Large LOCA initiating event frequency is 2.0E-04 Events/Reactor Year. From NUREG/CR-4550/Vol. 3 (Analysis of Core Damage Frequency from Internal Events: Surry, Unit 1) the operator failure frequency for failure to shift to hot leg recirculation is 8.0E-05/Event. The likelihood of core damage given Large LOCA and failure to initiate hot leg recirculation is:

CDF = LLOCA x Operator Error
CDF = 2.0 E-04 x 8.0 E-05 = 1.6 E-08 / Reactor Year

This frequency is considered negligible in relation to other causes of core damage.

IE6: The instrument tube breach as a potentially unique small LOCA is not discussed. (Section 2.1.4 of this report)

Response:

Instrument tube breach is not considered as a small LOCA in the PSA since coolant loss is not expected to exceed the makeup capability of normal charging.

The response to NRC Question 492.07N (attached) in the STPEGS FSAR states "...up to three (3) BMI thimble tubes can fail simultaneously with a complete instantaneous guillotine break, and the coolant loss can be made-up by the output of the on-line charging pump. Since the coolant loss would not exceed the makeup capability of normal charging, no SI (safety injection) signal is generated." Because no LOCA is initiated, instrument tube breech is not included in the small LOCA category. In addition, it is judged that the likelihood of simultaneous failure of more than 3 BMI thimble tubes is very low.

Question 492.07N

Do you feel the same vibrational problems are possible at STP? If you do, then quantify the safety impact of such a problem. If you do not, then explain any design differences between STP and Paluel that lead to this conclusion.

Response

As was previously noted (letter ST-HL-AE-1334, dated 2/3/86) the vibrational problem experienced at Paluel is the vibration of the BMI thimble, not vibration of the reactor vessel lower internals. The South Texas Units 1 & 2 use a flux thimble with a nominal outside diameter of .313 in. The Paluel units (1, 2, 3, 4) are using a thimble with an outside diameter of .295 in. The South Texas Project thimbles also have a slightly thicker wall than the Paluel thimbles. The larger thimble also results in a smaller annular gap between the flux thimble and the inside of the BMI columns. (Unit 1 will be modified such that the BMI column gap size is similar to Unit 2.) In 55 conclusion, the stiffer South Texas Project thimbles, with the smaller gaps, will perform satisfactorily based on the European plant experience to date.

With respect to the safety aspects of a thimble wear problem if it were to occur, we do not believe the issue to be a safety concern. Previous evaluations have been made by Westinghouse regarding the failure of flux thimble tubes. The evaluation concluded that up to three (3) BMI thimble tubes can fail simultaneously with a complete instantaneous guillotine break, and the coolant loss can be made-up by the output of the on-line charging pump. Since the coolant loss would not exceed the make-up capability of normal charging, no SI (safety injection) signal is generated. The occurrence of a thimble tube leak would be identified by the detectors in the seal table room.

It should be pointed-out that the assumption of three tubes rupturing at the same time is highly conservative. As noted above, even if the tubes ruptured, the plant would easily be able to complete a controlled shutdown so that the leaking thimble could be either isolated or replaced.

Appendix 3: HLP Responses to Issues Raised During this Review

IE5: The need to switchover from cold leg to hot leg recirculation to avoid boron precipitation is not addressed. (Section 2.1.2 of this report)

Response:

Switchover from cold leg recirculation to hot leg recirculation to avoid boron precipitation is not included in the PSA since it was not considered as leading to core melt. If it were assumed to lead to core melt it is estimated that its contribution to CDF would be approximately 0.01% or less.

Reference:

ERG Background document ES-1.4 LP Rev. 1A July 1, 1987. This document discusses the need for switching to hot leg recirculation. The basis for the switch to hot leg recirculation is the design basis cold leg LOCA (by definition a Large LOCA in the PSA). The switch to hot leg recirculation is considered to be necessary, using conservative analyses, to limit the boron concentration increase that occurs in the RPV after the design basis cold leg break. Boron precipitation could reduce heat transfer from the fuel to the reactor coolant. The plant emergency procedures discuss the steps necessary to achieve hot leg recirculation (POP05-EO-ES14). Failure to shift to hot leg recirculation is not considered as leading to severe core damage in the PSA and was not included in the Large LOCA event tree. If the event were included, and if the assumption is made that failure to shift to hot leg recirculation leads to core damage, the frequency of core damage associated with this failure can be determined by multiplying the Large LOCA initiating event frequency (per year) by the operator failure frequency for this event. From the PSA, the Large LOCA initiating event frequency is 2.0E-04 Events/Reactor Year. From NUREG/CR-4550/Vol. 3 (Analysis of Core Damage Frequency from Internal Events: Surry, Unit 1) the operator failure frequency for failure to shift to hot leg recirculation is 8.0E-05/Event. The likelihood of core damage given Large LOCA and failure to initiate hot leg recirculation is:

CDF = LLOCA x Operator Error
CDF = 2.0 E-04 x 8.0 E-05 = 1.6 E-08 / Reactor Year

This frequency is considered negligible in relation to other causes of core damage.

Appendix 3: HLP Responses to Issues Raised During this Review

IE6: The instrument tube breach as a potentially unique small LOCA is not discussed. (Section 2.1.4 of this report)

Response:

Instrument tube breach is not considered as a small LOCA in the PSA since coolant loss is not expected to exceed the makeup capability of normal charging.

The response to NRC Question 492.07N (attached) in the STPEGS FSAR states "...up to three (3) BMI thimble tubes can fail simultaneously with a complete instantaneous guillotine break, and the coolant loss can be made-up by the output of the on-line charging pump. Since the coolant loss would not exceed the makeup capability of normal charging, no SI (safety injection) signal is generated." Because no LOCA is initiated, instrument tube breech is not included in the small LOCA category. In addition, it is judged that the likelihood of simultaneous failure of more than 3 BMI thimble tubes is very low.

IE7: The ability of STPEGS to mitigate a V sequence LOCA should be discussed to justify screening such sequences from the analysis. (Section 2.1.6 of this report)

Response:

INTRODUCTION

Presented here is a model that bounds the upper limit of the frequency of containment bypass sequences at the STP Unit 1 or 2. The various places that have the high pressure-low pressure boundaries between the RCS and the other systems is discussed in detail in Reference 1. Of these, the lines most likely to be subject to the bypass sequences are discussed in this analysis. These are the three Low Head Safety Injection lines. The section of these lines close to the RCS are rated for the high RCS pressure. Each of these three sections contains two check valves (SI0038 and RH0032) and a motor-operated valve RH0031. The MOVs are normally open and are power locked out at the MCC. Beyond this MOV, the system is rated for a lower pressure, and in this section are the RHR heat exchangers and their flow control valves. Both the LHSI and the RHR pumps feed into the inlet side of each heat exchanger.

The RHR pumps are separated from the heat exchangers by a check valve (RH0065), but the entire RHR system is situated inside the containment. The LHSI pumps are separated from the heat exchangers by similar check valves inside the containment, but the rest of the LHSI system is outside the containment.

ASSUMPTIONS

1. The leakage/rupture failure rates for the first two check valves are assumed to be the same (e.g., valves SI0038A and RH0032A). These valves are both rated for pressures that exceed normal reactor coolant system operating pressure. The leakage/rupture failure rate for the third check valve is different (e.g., valve SI0030A). This valve is rated for a pressure of approximately 600 psig.

2. The space between the first two check valves is not continuously monitored. Minor leakage past the first valve (e.g., valve SI0038A) may pressurize this space and cause undetected high differential pressure across the second valve (e.g., valve RH0032A). It is conservatively assumed that both of these valves are exposed to full system pressure for the entire period between refueling outages. It is also assumed that if the space between these valves is pressurized and one of the valves fails catastrophically, the other valve will be exposed to a sudden pressure pulse.

3. The RHR relief valve (e.g., valve PSV3934) is rated to open at approximately 600 psig, and it has a rated flow capacity of approximately 20 gpm water at that pressure.

4. The RHR relief valve will open if minor leakage occurs through the first two valves (e.g., valves SI0038A and RH0032A) and this line is pressurized above approximately 600 psig. The relief valve discharges to the pressurizer relief tank. This leakage will be quickly detected, and the plant will be shut down and depressurized. Therefore, the third check valve (e.g., valve SI0030A) is not pressurized until both of the first two valves fail.

5. The first two check valves are confirmed closed by functional tests performed at the end of every refueling outage. These tests are also performed before the plant enters Mode 2 after every other cold shutdown outage. This analysis accounts only for the tests performed every 18 months during the regular refueling outage.

6. The minimum allowable pressure in the accumulators is approximately 586 psig. The RHR relief valve setpoint is approximately 600 psig. Therefore, if only the second check valve develops a leak (e.g., valve RH0032A), it is assumed that the RHR relief valve will not open, and this leak will remain undetected. However, if both the second and third check valves develop leaks, the resulting loss of accumulator level will alert the operators to this condition, and the plant will be shut down. Therefore, accumulator level provides an effective method for determining that at least one of these valves is intact during normal plant operation (e.g., valve RH0032A or valve SI0030A.).

7. No functional tests are performed to verify that the third check valve is closed while the plant is operating at power (e.g., valve SI0030A). This valve may be stuck in the open position if it failed to close after previous LHSI system operation.

8. As long as the leakage of the RCS past the first two check valves is within the capacity of the relief valve, the two check valves (e.g., RH0065A and SI0030A) will not be exposed to pressures above 600 psig. If the leaks are beyond the capacity of the relief valve, then the pressure will start rising unless another relief path is available. We assume that the heat exchanger and the piping survive the increased pressure, and the two check valves are the weak points in the system due to failure of the check valve disk. As soon as one of the two check valves fails, the pressure will no longer challenge the heat exchanger, the piping or the other check valve. Since the two check valves are identical in design, it is equally likely that either of the two check valves fails first.

9. So long as the leak past the first two valves is within the capacity of the charging pump, the leak will be treated as a very small LOCA whether it is inside or outside the containment. Plant shutdown can be attained before the RWST water is exhausted. There is a range of leak rates beyond the capacity of this charging pump, for which the above still holds true, but conservatively, we assume that any leak greater than the makeup capacity of the charging pump (120 gpm) is a bypass sequence.

10. The leakage past the first two check valves in excess of 20 gpm can be detected because of the indications from the RCS PRT. The location of the leak can be detected from the temperature and pressure alarms from the pressurized line; TA857, TA874, PA861. To terminate the leak, the operator would have to close the MOV RH0031A in the high pressure line. This valve is normally in the open position with its power locked out at the MCC. This action then will have to be performed at the MCC.

MODEL

In general, the frequency of failure for two valves, V_1 and V_2, in series (V_1 is assumed to be nearest to the RCS) can be expressed as

$$\lambda_s = \lambda(V_1)*P(V_2|V_1) + \lambda(V_2)*P(V_1|V_2) \qquad (1)$$

where

λ_s	=	the frequency of failure of both series valves.
$\lambda(V_1)$	=	the frequency of random, independent failure of valve V_1.
$P(V_2\|V_1)$	=	the conditional likelihood that V_2 is failed, given that V_1 fails.
$\lambda(V_2)$	=	the frequency of random, independent failure of V_2 (events per hour).
$P(V_1\|V_2)$	=	the conditional probability that V_1 is failed, given that V_2 fails.

$P(V_2|V_1)$ and $P(V_1|V_2)$ are composed of both random, independent, and demand type failures of the second valve.

In some cases, the random, independent failure frequencies and conditional probabilities for the two valves will be approximately equal, but in other cases, they will not. For example, if V_1 leaks slightly but V_2 does not, V_2 would be exposed to the differential pressure loading to which V_1 is normally exposed. In this situation, V_1 would have RCS pressure on both sides of the disc and would be expected to have a lower failure rate than V_2, which is exposed to a greater differential pressure. Thus, Equation (1) could be written as

$$\lambda_s = \lambda(V_1)*P(V_2|V_1)*(1-P_I) + \lambda'(V_1)*P'(V_2|V_1)*P_I$$

$$+ \lambda(V_2)*P(V_1|V_2)*(1-P_I) + \lambda'(V_2)*P'(V_1|V_2)*P_I \qquad (2)$$

where

P_I = the probability that the space between valves is pressurized to RCS pressure.

$\lambda'(V_1)$ = the frequency of a random, independent failure of V_1, given that the space between valves is pressurized (events per hour).

$P'(V_2|V_1)$ = the conditional probability that V_2 fails, given that V_1 has failed and the space between valves is pressurized.

$\lambda'(V_2)$ = the frequency of a random, independent failure of V_2, given that the space between valves is pressurized.

$P'(V_1|V_2)$ = the conditional probability that V_1 fails, given that V2 has failed and the space between valves is pressurized.

On the basis of the loadings across the valve discs, the following assumptions appear to be reasonable for the lines that contain the check valves.

1. $\lambda'(V_2) \simeq \lambda(V_1)$.
2. $\lambda'(V_1)$ is small compared to $\lambda(V_1)$.
3. $\lambda(V_2)$ is small compared to $\lambda'(V_2)$.
4. $P'(V_1|V_2) \simeq P(V_2|V_1)$.

Substituting for $\lambda'(V_2)$ and $P'(V_1|V_2)$

$$\lambda_s \simeq \lambda(V_1)*P(V_2|V_1)*(1-P_I) + \lambda'(V_I)*P'(V_2|V_1)*P_I \qquad (3)$$

$$+ \lambda(V_2)*P(V_1|V_2)*(1-P_I) + \lambda(V_1)*P(V_2|V_1)*P_I$$

or

$$\lambda_s \simeq (V_1)*P(V_2|V_1) + \lambda'(V_1)*P'(V_2|V_1)*P_I \qquad (4)$$
$$+ \lambda(V_2)*P(V_1|V_2)*(1-P_I)$$

The third term in Equation (3.4) is small compared to the first, therefore

$$\lambda_s \simeq \lambda(V_1)*P(V_2|V_1) + \lambda'(V_1)*P'(V_2|V_1)*P_I \qquad (5)$$

As a conservative upper bound, it can be argued that

$$\lambda_s = \lambda(V1)*P(V_2|V_1)*(1+P_I) \tag{6}$$

Because only a minute amount of leakage is required to pressurize the space between valves, it is assumed that PI approaches 1.0. Therefore

$$\lambda_s \simeq 2*\lambda(V_1)*P(V_2|V_1) \tag{7}$$

Given that V_1 has failed independently, V_2 could fail upon demand (due to the sudden pressure challenge), or it may fail randomly in time, sometime after failure of V_1. The latter failure mode is represented by the standby redundant system model.

The term $P(V_2|V_1)$ in Equation (7) contains two components: one representing random failures of the second valve, given that the first valve has failed, and the second representing a demand failure at the time the first valve failed.

The determination of the frequency of occurrence of random failures is facilitated by assuming that the two series check valves in each path represent a standby redundant system, and failure of the downstream check valve cannot occur until failure of the check valve nearest to the reactor coolant system loop has occurred. The probability of random failure (unreliability) for a single injection path is given by

$$Q_{path} \simeq 1 - e^{-1t} (1 + \lambda t) \tag{8}$$

where λ is the appropriate failure rate of a single check valve. In this study λ is the frequency of exceeding leakages of 120 gpm. This expression was then used to derive a failure (or hazard) rate for the path. That is,

$$\lambda_{path}(t) = \frac{-1}{(1 - Q_{path})} \frac{d}{dt} [1 - Q_{path}] \tag{9}$$

or

$$\lambda_{path}(t) = \frac{\lambda dt}{(1 + \frac{1}{\lambda t})} \tag{10}$$

As noted earlier, the plant is expected to go to cold shutdown once a year at which time these valves will be inspected. If it is determined that the system is not functioning, it is repaired at that time. Therefore, the time-dependent failure rate is bounded at 1 year. The average failure rate over a time period, T, is given by

$$\langle\lambda_{\text{path per reactor year}}\rangle = \frac{1}{T}\int_0^T \frac{\lambda dt}{\frac{1}{(1+\lambda t)}} \tag{11}$$

$$= \frac{1}{T}\left[\lambda T - \ell n\,(1+\lambda T)\right]$$

When $\lambda T \ll 1$, this result can be expanded to obtain

$$\langle\lambda_{\text{path}}\rangle = \frac{1}{2}\lambda^2 T \tag{12}$$

The demand component of the path failure frequency is merely the product of λ and the demand failure rate, λ_d. Thus, $\langle\lambda_{path}\rangle$

$$\langle\lambda_{\text{path}}\rangle = \lambda\left[\frac{\lambda T}{2} + \lambda_d\right] \tag{13}$$

Finally, the above expression for $\langle\lambda_{path}\rangle$ is multiplied by a factor of 2 to account for the logic used in developing Equation (7). This logic is that the two valves can fail in either sequence because of an assumed high likelihood of inboard valve leakage and pressurization of the space between valves. Thus, the final expression for the series valves in the injection lines is

$$\langle\lambda_{\text{path}}\rangle = 2\lambda\left[\frac{\lambda T}{2} + \lambda_d\right] \tag{14}$$

Equation (14) defines the frequency with which the low pressure piping is pressurized. Once it is pressurized, it is equally that either the RHR side check valve or the LHSI side check valve will fail. If the RHR side valve fails, then the leakage is inside the containment and is treated as a small or medium LOCA. If the LHSI side valve fails, then it is a containment bypass event, and specific actions have to be taken to mitigate it. The actions considered here are the manual closure of RH0031. The expression for a containment bypass sequence is any of the three LHSI injection lines can then be written as:

$$Q_v = 3\lambda[\lambda T + 2\lambda_d]*0.5*[HE + Q_d] \tag{15}$$

where

HE is the failure frequency for the operators to diagnose the cause of the alarms and to manually close RH0031

Q_d is the failure of RH0031 to close on demand

T is the exposure time for the two high pressure check valves, the time between refueling outages (18 months)

0.5 accounts for only the scenarios where SI0030 fails first

FAILURE DATA

1. Check Valve SI0038

• Develop leak > 120 gpm	Mean	4.00E-08
	5th percentile:	1.40E-09
	50th percentile:	1.45E-08
	95th percentile:	1.45E-07
• Fails to hold under pressure pulse	Mean:	2.26E-04
	5th percentile:	2.66E-05
	50th percentile:	1.37E-04
	95th percentile:	6.82E-04

2. Check Valve RH0032:

• Develops leak > 120 gpm	Mean:	4.00E-08
	5th percentile:	1.40E-09
	50th percentile:	1.45E-08
	95th percentile:	1.45E-07
• Fails to hold under pressure pulse	Mean:	2.26E-04
	5th percentile:	2.66E-05
	50th percentile:	1.37E-04
	95th percentile:	6.82E-04

3. Check Valve SI0030:

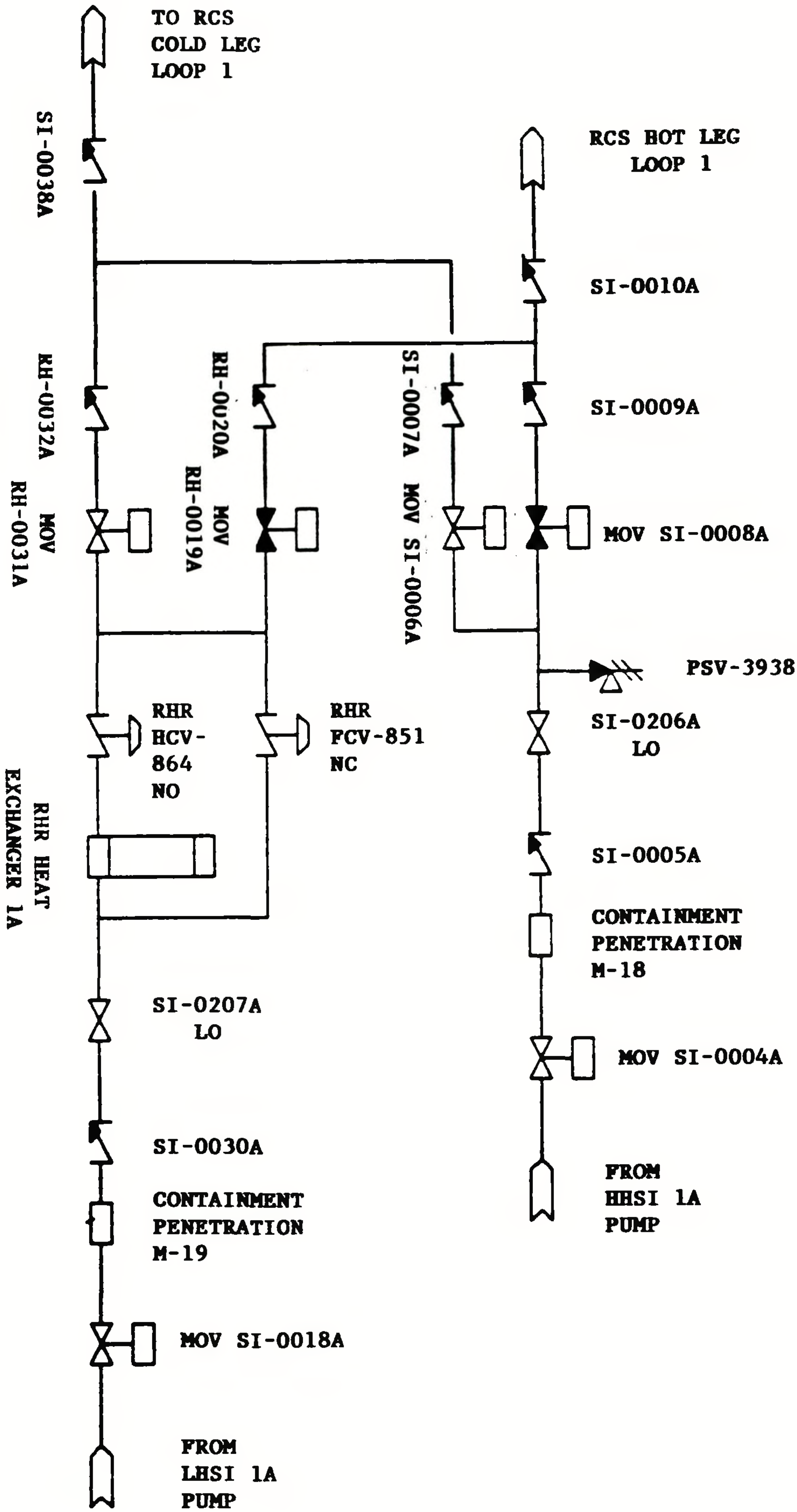
• Fails to hold under pressure pulse	Guaranteed failure (1.0)

4. Check Valve RH0065:

• Fails to hold under pressure pulse	Guaranteed failure (1.0)

OPERATOR ACTIONS

After the failure of the first two check valves in the high pressure section of the injection lines, there will be ample signal to the control room that the RCS has leaked into the low pressure piping. If the relief valve lifts, the control room operators will be alerted by the alarm received from the RCS PRT about the increasing water level. Even if the relief valve does not lift, there will be alarms from the temperature and pressure instrumentation in the low pressure piping. To close RH0031, an



ECCS Train A
Simplified Schematic

ATTACHMENT 1
ST-HL-AE-3478
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Appendix 3: HLP Responses to Issues Raised During this Review

IE8: A discussion of the letdown line break is not provided. (Section 2.1.6 of this report)

Response:

A letdown line break is not included in the PSA since break flow is limited to less than the charging pump capacity.

The letdown line break is described in UFSAR Chapter 15. The flow limiting orifices limit break flow to less than charging pump capacity, thus this break is not a LOCA. Because it is not a LOCA it is not included in Table 5.4-31 which includes "... those systems that may have a potential of initiating a V Sequence event." (PSA page 5.4-151).

Appendix 3: HLP Responses to Issues Raised During this Review

IE9: Minimum containment cooling requirements are not sufficiently discussed. (Section 2.1.8 of this report)

Response:

The concern regarding minimum containment cooling requirements is summarized into two parts. First, the PSA does not explicitly discuss the effect of no containment spray on the calculated containment pressure response. Second, a discrepancy exists in the PSA with respect to minimum requirements for maintaining containment integrity during the recirculation phase of an accident. Note that the following discussion relates to containment integrity and does not impact CDF as estimated by the PSA.

Failure of the containment spray system to actuate following a large break LOCA results in a peak calculated containment pressure less than the design value of 56.5 psig based on an analysis performed by Bechtel (Reference ST-3R-HS-00805 dated November 17, 1989). In summary, the analysis assumes only one RCFC and its associated CCW pump train is operating with no containment spray. The corresponding RHR pump train is also available for LHSI recirculation flow heat removal. The peak calculated containment pressure was 42 psig at approximately 1200 seconds in the subject analysis. Table 6.2.1.1-11 of UFSAR Section 15.6 shows a peak calculated containment pressure of 37.5 psig at 83 seconds for the design basis accident.

Thus, the above described analysis supports the PSA success criteria that containment spray injection and spray recirculation are not required for containment integrity, but are helpful for fission product removal (or scrubbing). Based upon the analysis performed, containment pressure will exceed the calculated peak pressure of 37.5 psig shown in the UFSAR, but will be less than the design value of 56.5.

The draft Sandia report also identified that a conflict exists in the PSA with respect to the minimum cooling requirements for maintaining containment integrity. The conflict exists between Chapters 5 and 16 of the PSA. Chapter 16 provides two different success criteria for coding plant damage states as either "containment heat removal and fission product scrubbing" or "containment heat removal only". Chapter 5 identifies a success criteria for event tree top events that corresponds to the "containment heat removal and fission product scrubbing" category and does not support the "containment heat removal only" success criteria. For the purpose of Level II analyses, the PSA conservatively bins the core damage sequences categorized as "containment heat removal only" into the plant damage state of "no containment heat removal and fission product scrubbing". Therefore, the conflict is a result of having a plant damage state category that is not currently used, but is available for future use provided the appropriate modification(s) to the event trees are made.

Appendix 3: HLP Responses to Issues Raised During this Review

The analysis identified and discussed above was not available prior to completion of the PSA, thus the event tree top event success criteria was established to correspond to that required for the "containment heat removal and fission product scrubbing" plant damage state. Sequences coded as being "containment heat removal only" represented only a negligible fraction of the calculated total CDF and were binned to a more conservative plant damage state. This binning assumption will be evaluated further during the Level II analysis.

The Sandia draft report also pointed out a concern with the statement that high head recirculation can provide adequate decay heat removal since the HHSI pump can not be aligned to its corresponding RHR heat exchanger. It is true that the HHSI pump and RHR heat exchanger can not be aligned for recirculation However, it is possible to remove decay heat in a high head recirculation mode.

The PSA models high head recirculation as an alternative to low head recirculation for removing core decay heat during small LOCAs. High head recirculation requires the availability of a HHSI pump and two RCFCs. The HHSI pump recirculates sump water inventory through the core. The RCFCs provide adequate heat removal capability at elevated containment temperatures. The condensate generated by the RCFCs replenishes the sumps for recirculation. Therefore, the PSA does not require an RHR heat exchanger for high head recirculation. However, by procedure, low head recirculation is the preferred method for long term core decay heat removal. Low head recirculation requires the availability of a LHSI pump and its corresponding RHR heat exchanger after the operator successfully depressurizes the reactor coolant system.

The basis for the use of two RCFCs to remove containment heat during recirculation phase is engineering judgement based on discussions with Westinghouse PRA personnel and technical analyses similar to that included in the SNL draft report. Westinghouse personnel who had performed similar PRA analyses on its plants have indicated in discussions with HL&P personnel that it was their judgement that two fan coolers alone are adequate for decay heat removal after successful RWST injection and after switchover to recirculation. In addition, an evaluation was performed by PLG which led to the same conclusion. Thus it has been assumed in the PSA that two RCFCs alone, after successful injection and initiation of recirculation, will prevent containment overpressurization.

As indicated by the SNL reviewer, and referring to the attached figures from the STPEGS UFSAR, core decay heat generation at approximately 4000 seconds (Figure 6.2.1.1-18) is approximately 200 x 106 BTU/hr.

It can be seen from Figure 6.2.1.1-3 that the heat removal rate of two RCFCs at 280°F is approximately 220 x 106 BTU/hr. If it is assumed that recirculation is initiated at 1216 seconds which is the case for the design basis LLOCA (Table 6.2.1.1-10), decay heat injection at that time is approximately 300 x 106 BTU/hr and containment and sump vapor temperatures are as shown in Figure 6.2.1.1-11 (approximately 235°F and 260°F respectively). Reference to steam tables indicate that containment vapor temperature and pressure increase due to the excess decay heat injection over removal rate during this period will not result in exceeding design containment pressure of 71.2 psia. Subsequently, decay heat injection is exceeded by the RCFC removal rate.

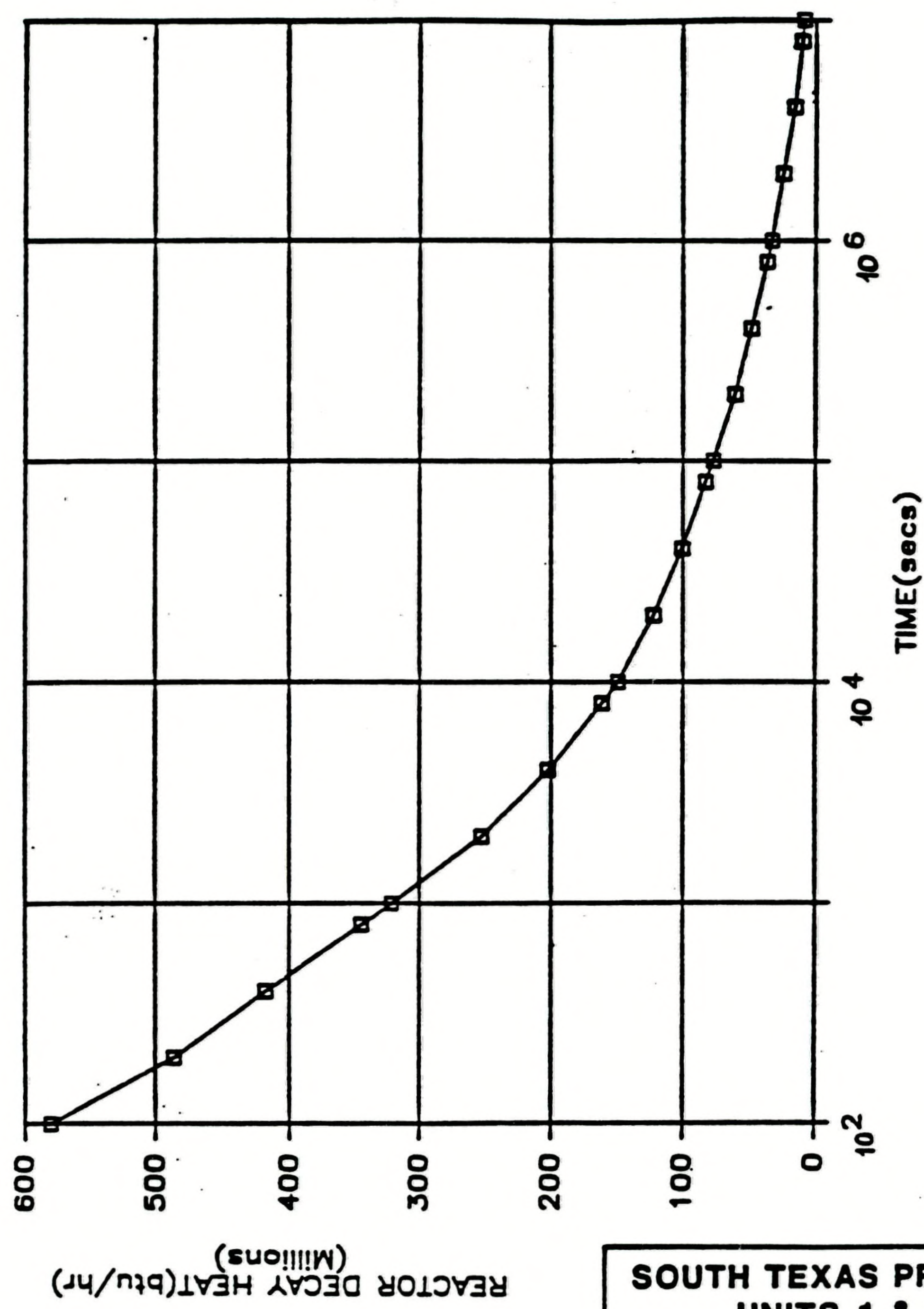
TABLE 6.2.1.1-10 (Continued)

ACCIDENT CHRONOLOGY

B. Most Severe Hot Leg Break

Break Type: Double-ended Guillotine Break with Max SI, Min CHRS

Time (Seconds)	Event
0	Break occurs
14.2	Accumulator injection begins
18.5	Peak Containment pressure during blowdown
21.0	ECCS injection begins
21.0	End of blowdown
37.4	Beginning of fan cooler operation
39.3	Peak Containment pressure
82.6	Beginning of Containment spray injection
103.7	End of core reflood
216.0	Containment pressure is 50 percent of design value
1,216.0	Beginning of recirculation

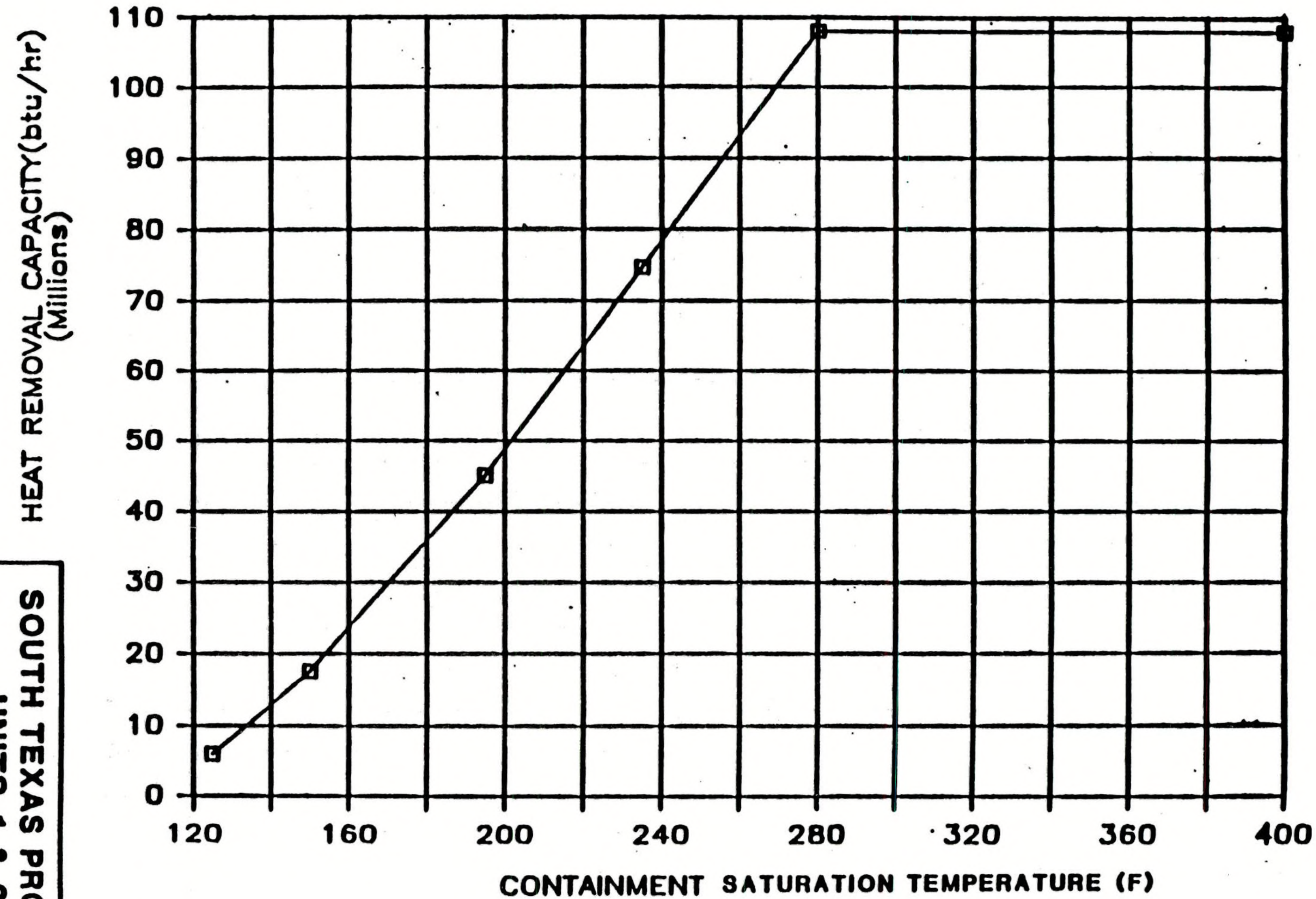


SOUTH TEXAS PROJECT
UNITS 1 & 2

REACTOR DECAY HEAT

Figure 6.2.1.1-18

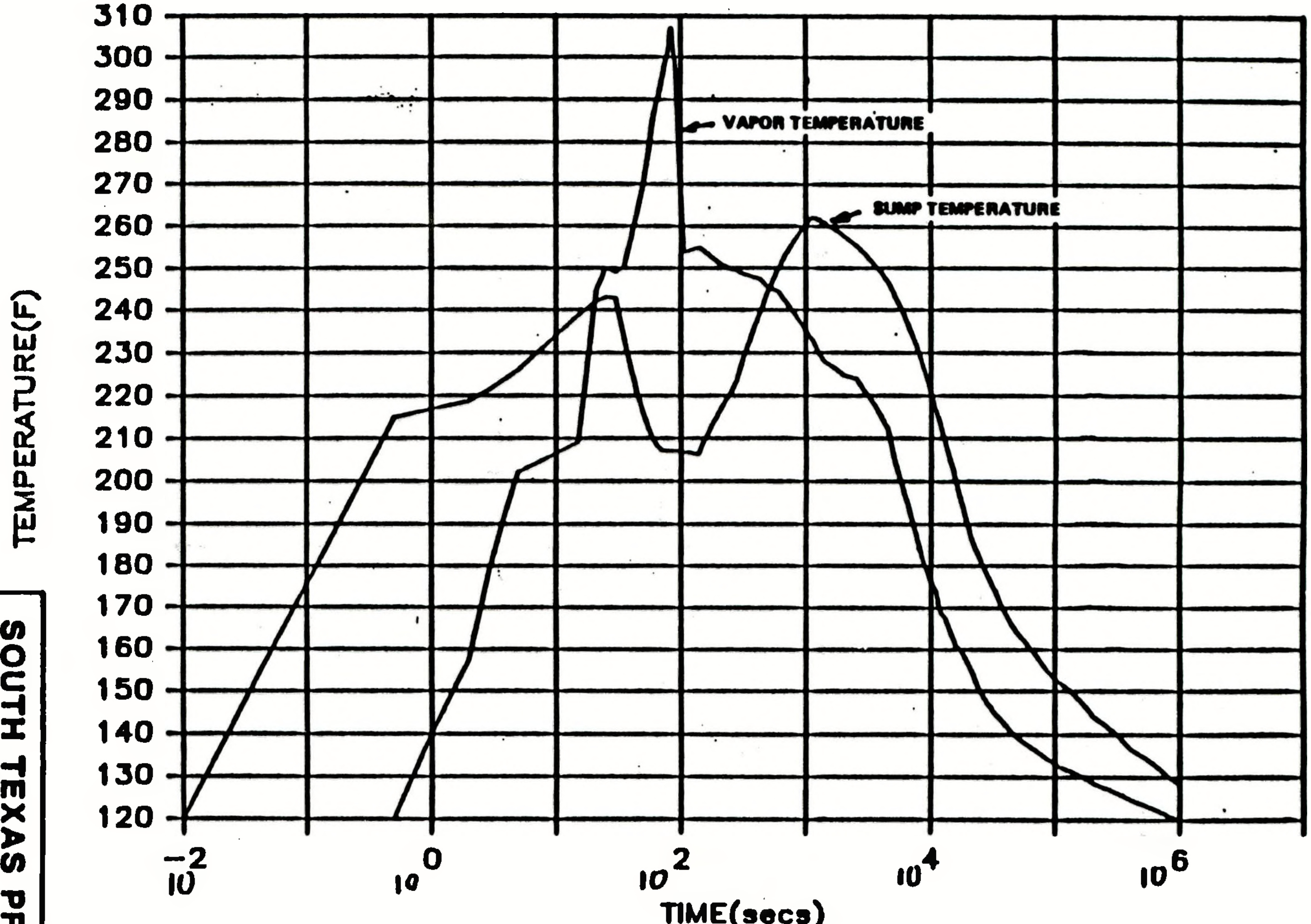
Revision 0



SOUTH TEXAS PROJECT
UNITS 1 & 2

FAN COOLER DUTY CURVE
PER UNIT

Figure 6.2.1.1-3 Revision 0



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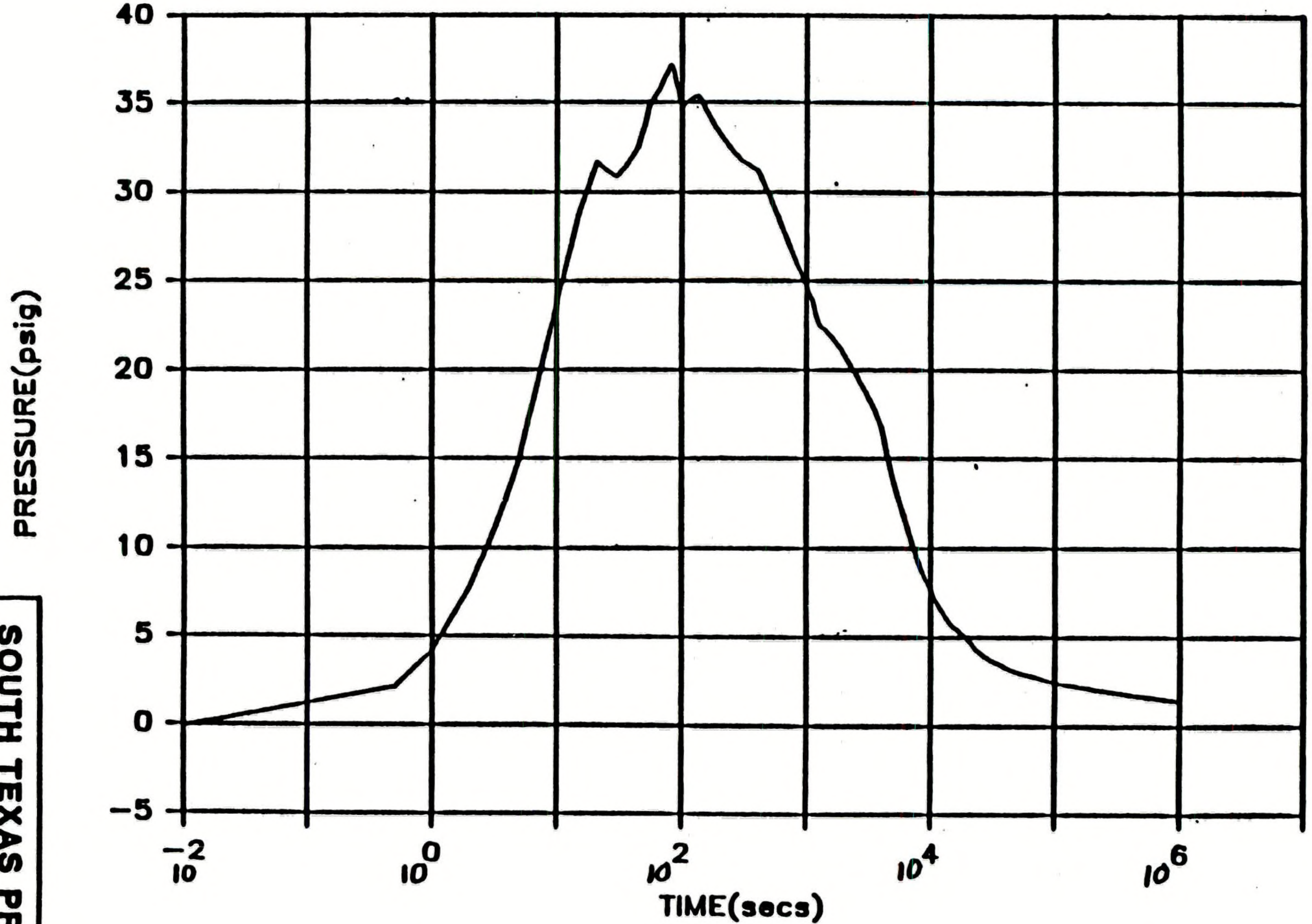
UNITS 1 & 2

LOCA-2 CONTAINMENT VAPOR AND SUMP WATER TEMPERATURES

Figure 6.2.1.1-11 Revision 0



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UNITS 1 & 2

LOCA-2 CONTAINMENT PRESSURE

Figure 6.2.1.1-5

Revision 0

Appendix 3: HLP Responses to Issues Raised During this Review

IE10: The assumption of no early containment failure is not discussed. (Section 2.1.8 of this report)

Response:

Early containment failure in the context of the Sandia review is not an issue for large dry PWR containments. Early containment failure due to the causes identified in the Sandia review will be investigated as part of the Level II analysis requirements of Generic Letter 88-20.

Early containment failure is typically defined as failure of containment at vessel failure or slightly after. The key point is early containment failure for large dry PWR containments occurs after the onset of core damage (see Sandia comments on page 12 of this report on causes, e.g. direct containment heating only occurs in high pressure melt scenarios at vessel breech, in-vessel steam explosion occurs during core slump (severe damage)). The PSA is a Level I model that stops when core damage occurs. The Level II analysis will investigate the likelihood and consequences of "early" containment failure after core damage.

Appendix 3: HLP Responses to Issues Raised During this Review

IE11: The three-inch criterion for containment pressurization is not justified. (Section 2.1.8 of this report)

Response:

The Sandia comment refers to the classification of hole sizes in the PSA event tree analysis of containment isolation failures. In the PSA and in other PLG PRAs on Westinghouse plants with large dry containments, penetrations that communicate with the RCS and/or the containment atmosphere having lines with inside diameter of 3 in. or less are classified as "small" and those with diameters of greater than 3 in. are classified as large. In the context of a Level 1 PSA this distinction has an impact on the plant damage state assignment but does not impact core damage frequency.

The selection of the 3 in. value is based on work in the full scope Level 3 PSA for Seabrook (SSPSA)(see Section 11.3 of PLG-0300) to examine self-limiting containment failure modes. It was determined that, for a hole size of about 3 inches, the containment pressure would rise until an equilibrium was reached between the pressurization driven by decay heat and containment leakage at a level of pressure that would not seriously challenge the structural integrity of the containment. The attached figures from the SSPSA show that:

- the probability of gross containment failure for wet sequences at 150 psia is less than 10-4 (Figure 11.3-14)

- at 21-22 hours after shutdown, a 3-inch diameter hole will prevent pressurization beyond 150 psia for wet sequences (Figure 11.3-1)

- at 24 hours after shutdown for the TE sequence, containment pressure is about 145 psia (Figure 2.2.4-1A)

In Section 16 of the PSA a detailed qualitative comparison was made between the STPEGS and Seabrook containments with results that point favorably to the use of this type of information from Seabrook on STPEGS. The key difference between the SNL calculation and the Seabrook calculation was the use of the 71.2 psia design pressure by SNL vs. 150 psia for Seabrook. The STPEGS PSA documentation should be revised to state that 3 in. would lead to a pressure rise toward equilibrium conditions at an elevated pressure much less than that needed to seriously challenge containment structural integrity.

Having stated this, it should be noted that all the penetrations that meet the criteria for containment isolation considerations of diameter 3 in. or less were classified as small, and full pressurization to failure was then assumed for no containment heat removal sequences.

The largest penetrations classified as small were the 3 in. RCP seal return and CVCS letdown lines. The only penetrations greater than 3 in. that were classified as large, no pressurization-type sequences that met the criteria of communicating with the RCS and/or the containment atmosphere were the containment purge lines whose diameter is 18 in. and corresponding area is 254 in^2. Hence, the PSA results would be no different if the criteria were changed to read, "all penetrations of 18 in. diameter or greater are considered large and anything smaller is considered small."

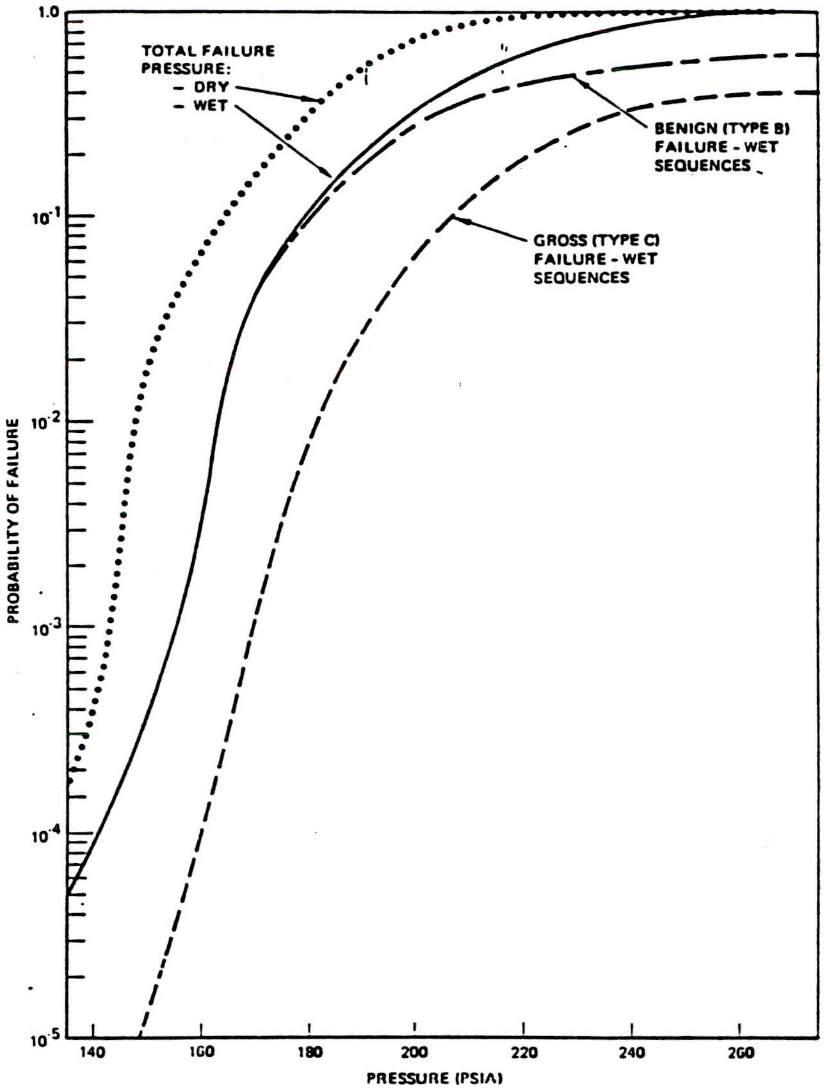


FIGURE 11.3-14. COMPOSITE CONTAINMENT FAILURE PROBABILITY DISTRIBUTIONS FOR BENIGN FAILURE, GROSS FAILURE, AND TOTAL FAILURE

11.3-42

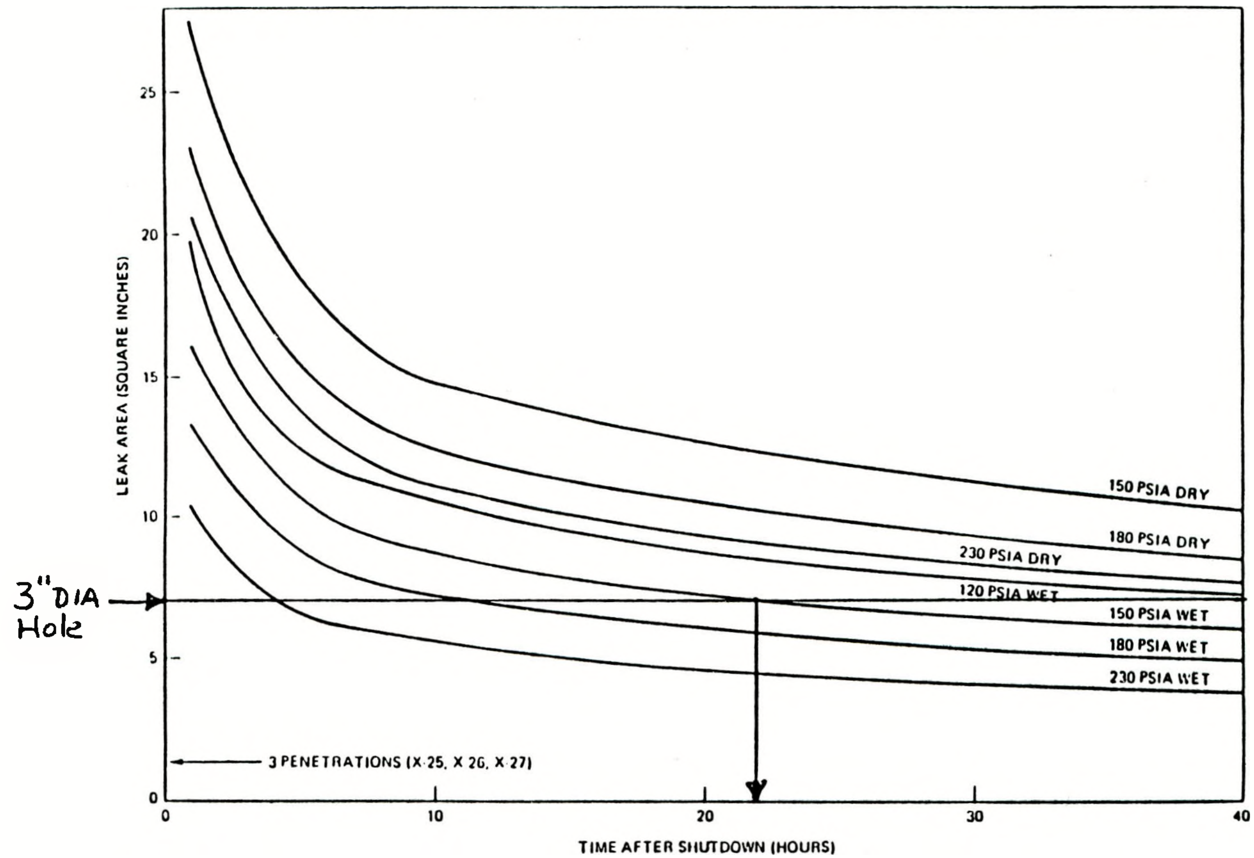


FIGURE 11.3-1. CONTAINMENT LEAK AREA REQUIRED TO ARREST PRESSURE RISE AS A FUNCTION OF SEQUENCE TYPE, PRESSURE, AND TIME AFTER SHUTDOWN

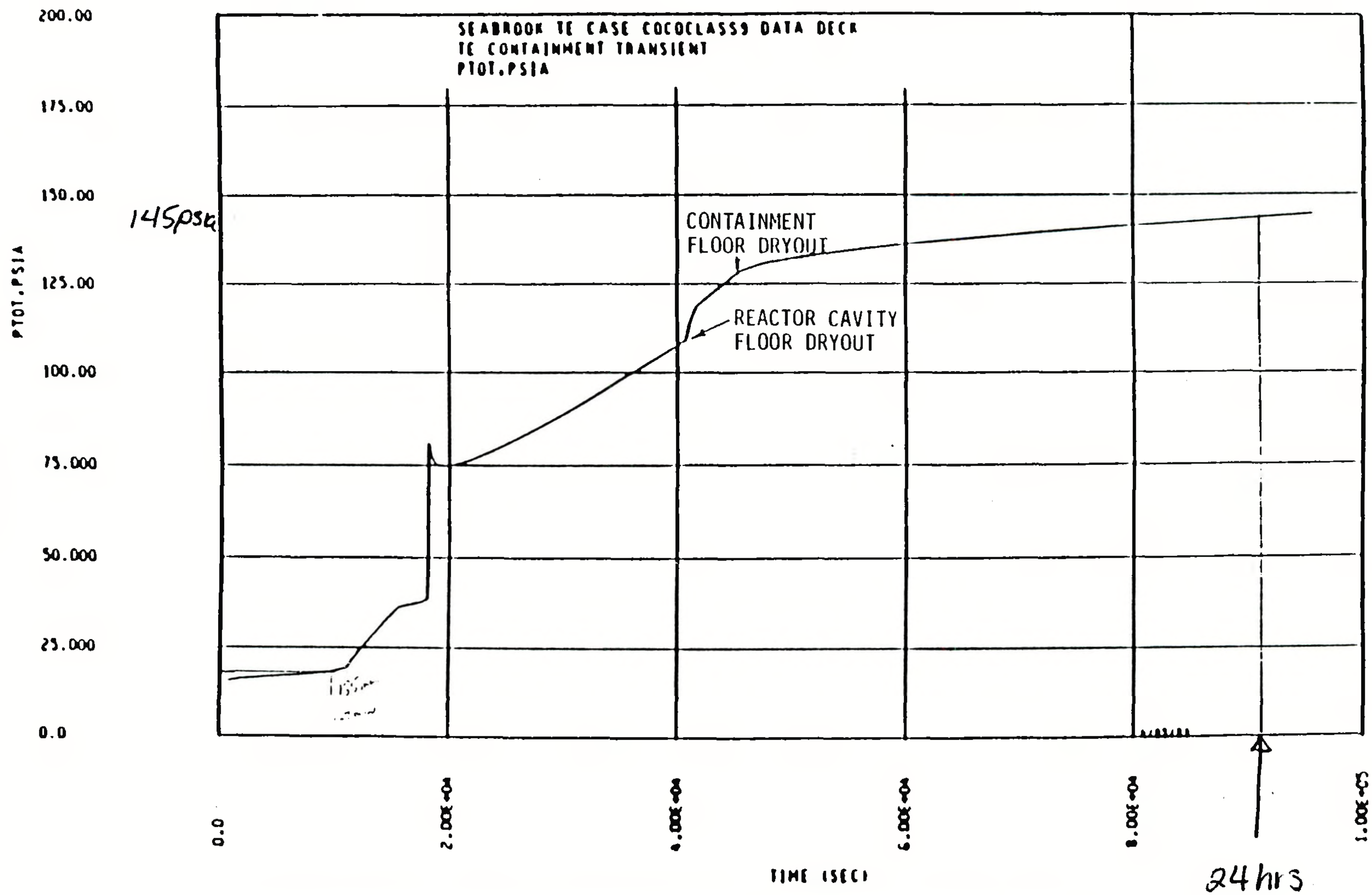


FIGURE 2.2.4-1A CONTAINMENT PRESSURE, PTOT, VS. TIME FOR THE TE CASE

IE12: I&C necessary for throttling HHSI is not included. (Section 2.2.2 of this report)

Response:

During the HL&P internal PSA review process, the phrase "throttling HHSI" was screened out several times. The reason for this screening was because the HHSI cannot be throttled. A re-review of the schematic drawings for the HHSI discharge valves show the circuit is "locked in" upon actuation, thus driving the valve stem from fully closed to open or vise versa. Therefore, the HHSI pumps and discharge valves cannot be throttled and no I&C is available to throttle the HHSI pumps. The phrase "throttling HHSI" is still present in the PSA and should be deleted or modified to reflect what is stated for Event 25 on page 5.4-16 of the PSA. This will be corrected in the next update of the PSA.

IE13: The ability of equipment in the PDP pump room to operate without forced cooling to the room is not justified. (Section 2.2.3 of this report)

Response:

A calculation has been completed to determine the impact of loss of room cooling in the PDP pump cubicle. The study indicates that the room temperature in the cubicle is approximately 115°F at the end of eight hours (see attached temperature profile). No credit is taken for mixing with outside air. This calculation is the basis for the assumption that the PDP can be operated with loss of room cooling under station blackout conditions with the TSC diesel available.

060053 (03/88)

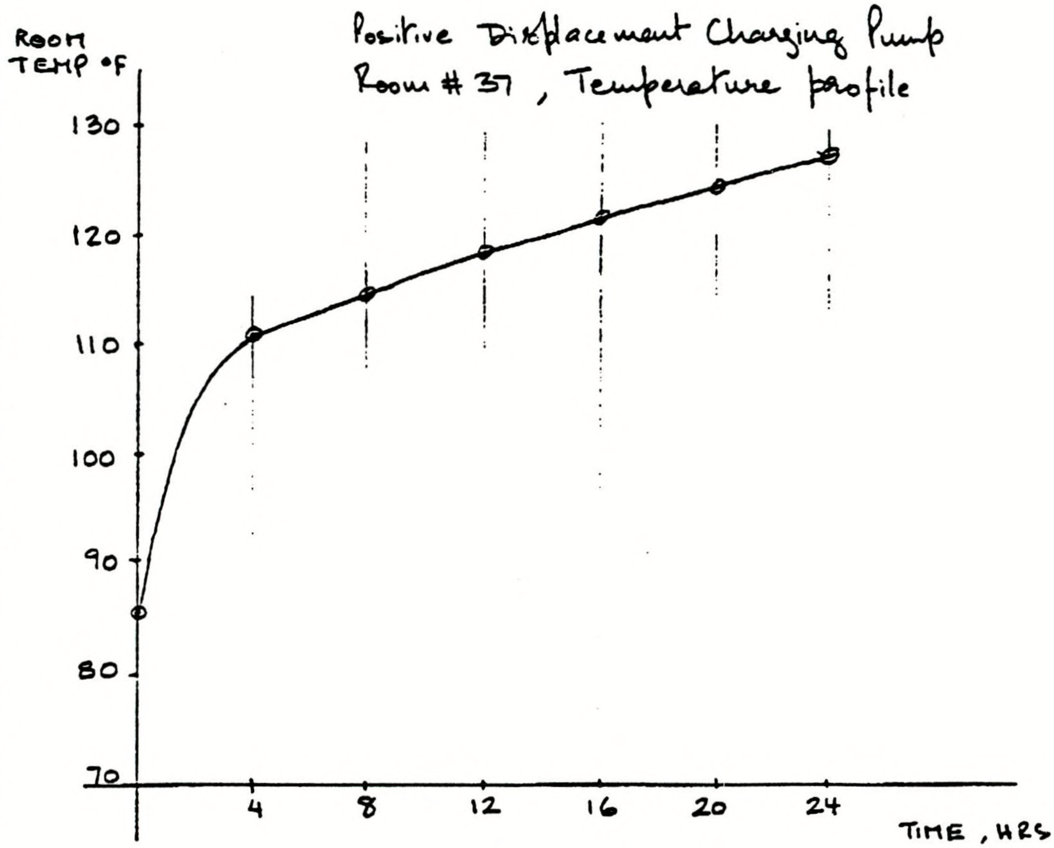
SOUTH TEXAS PROJECT
ELECTRIC GENERATING STATION
HOUSTON LIGHTING & POWER

GENERAL COMPUTATION SHEET

SUBJECT PD Pump Rm Ht up UNIT/s 1 & 2

CALC NO. MC 6182		SHT 17A OF 21
REV.	PREPARER/DATE	REVIEWER/DATE
0	VSB 5/17/90	J.R.P. 5/23/90

Positive Displacement Charging Pump
Room # 37, Temperature profile



Room temp after 8 hr period = 114.65 °F

USE 115 °F

Room temp after 24 hr period = 126.93 °F
~ 127 °F

Appendix 3: HLP Responses to Issues Raised During this Review

IE14: The exclusion of instrument air (IA) from the mitigating systems is not clearly justified. (Section 2.2.5 of this report)

Response:

Instrument air is a nonsafety system at STPEGS and is not required for safe shutdown of the plant. Many such nonsafety systems were screened in the early stages of the PSA and are not described in the final PSA.

The exclusion of instrument air as a support system is based upon the system screening process described in Chapter 4.2 (Section 4.2.1.2) of the PSA. This system is only one of many that were screened from analysis in the PSA because their failures did not affect successful operation of the systems which were analyzed. Loss of instrument air is included as a unique support system failure leading to an initiating event as described in the Sandia review. Justification of the exclusion of instrument air and other systems is included in system notebooks at STPEGS. Inclusion of justification for all of the other unnecessary STPEGS systems which are not modeled in the PSA is not felt to be warranted.

Appendix 3: HLP Responses to Issues Raised During this Review

IE15: The ability of EAB HVAC to provide adequate cooling in a once through mode with no cooling provided to AHUs is not explicitly justified. (Section 2.3.2 of this report)

Response:

Sections 12.2 through 12.5 of the PSA addresses the analysis performed to determine the success criteria for EAB HVAC. In particular, these sections present the basis for a very detailed evaluation to show that the use of the EAB HVAC system in the once-through (smoke-purge) mode will be effective in preventing components in the EAB from overheating.

The attached pages from Section 12.2 summarize the cases which were studied and the analyses performed to estimate the temperatures in the EAB under expected heat loads. These cases include 2 analyzing HVAC operation in a once-through smoke-purge outside-air-circulation mode with no chillers in operation. The uncertainty in operating temperature determined by these cases was combined with equipment temperature fragilities as described in the above mention sections, and the likelihood of equipment failure determined for the loss of HVAC event trees.

12.2 ELECTRICAL AUXILIARY BUILDING HEATUP ANALYSIS

It was assumed in the mechanical support systems event tree model that at least 450 tons of chiller capacity is required in each of the two normally operating EAB HVAC trains to provide the necessary cooling function to the EAB and that, if either the 300-ton or the 150-ton chiller on the operating EAB HVAC train fails, the associated ECH train is considered unavailable. The operators were required to start the standby EAB HVAC train and its associated ECH train, thereby reestablishing the required 900-ton chiller capacity for the EAB HVAC system. However, on failure of another EAB HVAC train or its associated ECH train, a requirement that the operators have to switch the EAB HVAC system to the smoke purge mode of operation and to open the door(s) connecting the electrical distribution room to its adjacent switchgear room as part of the operator action to mitigate the situation was modeled in the mechanical support system event tree. The open door(s) allows relatively cooler air from the switchgear room to mix with the hotter air in the distribution room. In practice, good mixing of air between the electrical distribution room and its adjacent switchgear room can be achieved by blowing relatively cooler air from the switchgear room into the distribution room and discharging the hot air from the distribution room using "elephant trunks" and blowers.

The degraded modes of EAB HVAC operation that are considered in the event tree model of mechanical support systems are

- One-Train Smoke Purge with No Chiller
- Two-Train Smoke Purge with No Chiller
- One-Train Smoke Purge with 450-ton Chiller Capacity in Line with the Train
- Two-Train Smoke Purge with 450-ton Chiller Capacity in Line with One of the Trains
- One-Train Closed-Loop Mode with 450-ton Chiller Capacity in Line with the Train

All other scenarios associated with the EAB HVAC systems are treated deterministically in the mechanical support system event tree structuring.

The room heatup analysis in the scenario of one closed-loop train of EAB HVAC operation with 450-ton chillers online with the train has been done by Bechtel Energy Corporation (Reference 12-1), and the results are shown in Table 12.2-1.

To analyze the air heatup in the switchgear rooms (which contain the switchgear solid state protective devices) and in the electrical distribution rooms (which house the battery chargers, and the 7.5-kVA and 15-kVA inverters) during the smoke purge modes of EAB HVAC operation, the HEATUP code (Reference 12-2) was used. The HEATUP code was designed to calculate room temperatures with outside ambient air as the cooling source. This mode of room cooling modeled in the HEATUP code is characterized as a once-through fan system supplying outside ambient air to rooms and exhausting to the atmosphere. The effect of the chiller on the influent air in the room heatup analysis was factored into the calculation by adding to the outside air temperature term in the code a negative temperature term corresponding to the temperature reduction in the influent air because of the chiller. HL&P calculations (Reference 12-1) showed that 450-ton chillers in line with a smoke purge train provide a reduction in influent air temperature of at least 32°F, assuming average humidity conditions for the influent air.

EAB HVAC Operating Mode	Lumped Model			Isolated Model 4.5 Switchgear					
				Train A		Train B		Train C	
	Train A Rooms	Train B Rooms	Train C Rooms	Switchgear	Distribution	Switchgear	Distribution	Switchgear	Distribution
One Train of Smoke Purge	132	129	138	131	157	128	135	134	151
Two Trains of Smoke Purge	122	20	126	120	144	119	127	123	140

Table 12.2-2. Switchgear and Distribution Rooms Heatup Analyses during 27 Hours of Smoke Purge Mode of HVAC Operation

Notes:

1. All values are in degrees Fahrenheit (°F).
2. Maximum outside ambient temperature is 95°F.
3. Trains A and B lumped models include the switchgear and distribution rooms. Train C lumped model includes the switchgear, distribution, and motor generator set rooms.
4. Smoke purge operation for these analyses included only the EAB HVAC fans with no ECH chillers running.

Table 12.2-3. Maximum Room Temperature Distribution under Various Degraded Modes of HVAC Operation						
EAB HVAC Operating Mode	**Train C Lumped Model Maximum Temperature (°F)**			**Train A Isolated Distribution Room Maximum Temperature (°F)**		
	Mean	**5th Percentile**	**95th Percentile**	**Mean**	**5th Percentile**	**95th Percentile**
Two-Train Smoke Purge	108	85	122	130	114	141
One-Train Smoke Purge with No Chiller	121	103	134	146	133	155
Two-Train Smoke Purge with 450-ton Chiller in One Train	< 91	< 82*	<104	<118	<101	<129
One-Train Smoke Purge with 450-ton Chiller in the Train	< 95	< 81**	<108	<129	<116	<139
One-Train Closed Loop with 450-ton Chiller in the Train†	95	85	105	134	120	148

*20th percentile value.
**10th percentile value.
† A normal distribution is assumed for maximum temperature variation under this mode of EAB HVAC operation.

IE16: The acceptability of one steam generator in removing decay heat without its PORV being available is not clarified in the System Description for AFW. (Section 2.3.2 of this report)

Response:

The PSA requires various combinations of AFW pumps and steam relief valves depending on the initiating event and the operator response modeled. First, each AFW pump is assumed to be dedicated to its associated steam generator, thus no credit is taken for the air operated AFW crossover valves for alternative alignments. For example, the plant model accounts for the possibility of an AFW pump delivering flow to a steam generator experiencing a tube rupture or steam line break, thus requiring the availability of at least a second AFW pump to deliver to an unaffected steam generator. Second, for the operator to depressurize a steam generator and maintain adequate decay heat removal, at least one AFW pump and its associated PORV must be available to an unfaulted steam generator. The setpoint for the steam generator PORVs can be adjusted manually by the operators, thus providing them the ability to depressurize the steam generators and the RCS for scenarios such as SGTR. However, most initiating events simply require decay heat removal which can be performed at Hot Standby conditions. The PSA assumes that one AFW pump and adequate steam relief (i.e., the PORV or two safeties) are adequate for decay heat removal at hot standby conditions without challenging the pressurizer PORVs. For ATWS events, two steam generators and their associated AFW pumps are required.

Reference 71 in the AFW System Description is summarized in the PSA in a very brief simplified way. Reference 71 discusses the results of a conservative study performed by Westinghouse for the Loss of Normal Feedwater and Feedwater Line Break events. The success criteria for this study was that the pressurizer will not go solid. The study concluded that AFW flow to one steam generator without operator action to lower the steam generator PORV setpoint within 20 minutes would result in the pressurizer going solid. Failure of this criteria does not necessarily result in core damage, but does challenge the pressurizer PORVs. The PSA correctly models this pressurizer PORV challenge.

Appendix 3: HLP Responses to Issues Raised During this Review

IE17: The screening of high and medium energy line breaks and cracks as initiating events except for LOCAs, main steam line breaks, and feedwater line breaks is not justified. (Section 3.1 of this report)

Response:

High energy line breaks are included in the PSA as described in Chapter 5. Medium energy line breaks (e.g., ECW, CCW, IA) are included as system initiators. Breaks in specific locations are not described or analyzed in the PSA as the general categories of breaks analyzed bound these other specific breaks.

For the example cited, a break in the steam supply to the turbine driven AFW pump, the steam line break from the PORVs or MSSVs outside containment bound the analysis.

IE18: The justification for excluding core blockage as an initiating event is not provided. (Section 3.1 of this report)

Response:

In Table 5.2-6 of the PSA, an initiating event category 1 is identified which includes "core blockage/boron precipitation" as one possible event. This event was not considered further for quantification in the PSA (Table 5.2-7). NUREG\CR-2300, the PRA Procedures Guide, does not list core blockage/boron precipitation in its list of PWR initiating events for consideration (see Table 3-4). In Table 3.5, a few examples are given of possible initiating events, including core flow blockage, which may be identified from the use of a master logic diagram. The possible cause identified with the example is corrosion or crud buildup. A review of other documents including the Indian Point PSA, the Seabrook PSA, WASH-1400, NUREG-1150, and EPRI NP2230 does not reveal the consideration of such an initiating event.

Boron precipitation during power operation of the plant is not considered a credible event (boron precipitation during a cold leg LOCA is addressed in question IE5). Corrosion/crud buildup would result in fuel "leakers" but would likely not result in a plant trip. Even if it did result in a trip, it would look like a transient and would be considered to be in the transient initiating event frequency.

Both STPEGS units have gone through extensive preoperational/acceptance testing of all safety and many nonsafety systems, including several weeks of hot functional testing of the primary system prior to fuel load. In addition, initial startup testing included ascension to full-power testing encompassing approximately six months. Section 14.2 of the UFSAR describes in some detail the preoperational and startup tests performed. In addition, the NSSS includes a Loose Parts Monitoring System as described in the UFSAR in Section 4.4.6.4. The core blockage as an initiating event was screened from consideration due to the extensive testing performed, the extensive and continued monitoring for loose parts in the NSSS, and the experience base which indicates that the event would be a very low probability event.

Appendix 3: HLP Responses to Issues Raised During this Review

IE19: Units in the data base tables of Section 7 are not provided. (Section 3.4.2 of this report)

Response:

The description of the basic events contained in the PSA data base is felt to sufficiently define the units, e.g. failure on demand implies per demand units, failure during operation implies per operating hour, maintenance frequencies are per hour, maintenance durations are in hours, etc.

IE19a: It is impossible to tell from the tables of the PSA data base which types of distributions are used for each frequency distribution. (Section 3.4.2 of this report)

Response:

This statement is true but incomplete. The types of distributions are completely described in PSA reference 7-17. This data base is proprietary; however, the data base was made available for review by Sandia during the November 1989 plant visit.

Appendix 3: HLP Responses to Issues Raised During this Review

IE20: The majority of the values used for the Human Error Rates (HERs) are conservative, the remainder are similar to values used in other PRA studies. The HER values used do not seem unreasonable but, how these values were derived is not always clear. (Section 3.4.5 of this report)

Response:

See Appendix 4.

Appendix 3: HLP Responses to Issues Raised During this Review

IE21: The table of the twenty one dominant sequences which identifies split fractions contributing to each sequence, Table 3.6-1 (Appendix 2) is not included in the PSA. (Section 3.6 and Section 4.3 of this report)

Response:

The top twenty-one dominant sequences are identified in the PSA in Table 2.1-3. However the sequences are not characterized in terms of the split fractions which make up the frequency of occurrence of the sequence. The characterization of the split fractions is left to the verbal description of the failures that make up the sequences in Table 2.1-3.

Approximately 1200 sequences make up the dominant sequence model, each sequence of which is a combination of split fractions. The dominant sequence model represents those sequences which total approximately 85% of CDF. The twenty-one sequences are a very small fraction of the total.

The intent of the PSA is to convey the results of the analysis and the higher level detail of the models and the quantification process (consistent with IPE, NUREG-1335, requirements). Much of the detailed quantification documentation was not included, including the dominant sequences (the 1200 and therefore the 21). When it was recognized that the greater detail on the 21 sequences would facilitate the review process, this detail was quickly supplied. This detail is now appropriately included in the SNL review package (see Appendix 2 of this report).

IE22: Quantification of LOSP sequences are such that the exposure time for the EDGs and the time for recovery of offsite power are inconsistent. (Section 5.1 of this report)

Response:

The quantification of electric power recovery after a loss of onsite and offsite AC power is described in the PSA. The quantification of recovery is based upon a time sequenced recovery model described in Chapter 15.6. In this model, consistent exposure times and recovery times are used (also see question IE20 and the response in Attachment II).

The process used to quantify offsite power recovery and diesel generator run times is vague. The following paragraphs are provided to briefly describe the process used.

The diesel generator systems analysis quantified the likelihood of diesel generator failure for a 24 hour mission time to be consistent with the mission times for the other systems analyzed in the PSA. The results of the system analysis were used in the electric power event tree as a screening value to identify important core damage sequences resulting from loss of offsite power and failure of the emergency diesel generators.

These important core damage scenarios were then analyzed in detail to determine times available for recovery of offsite power and/or diesel generators given the plant conditions that exist for the sequence. A time sequenced model for offsite power and diesel generators was then quantified for each important scenario. The sequences identified in the top 21 core damage scenarios are actually the result of the time sequenced quantification of loss of offsite power and diesel generators with appropriate allowance for the frequency of recovery of the offsite grid and/or the diesel generators.

Section 15.6.2 describes the time-dependent power failure analysis in more detail.

Appendix 3: HLP Responses to Issues Raised During this Review

Additional Comments By HLP:

SECTION 1.1 - METHODOLOGICAL OVERVIEW

This section presents a fairly accurate description of some of the key differences between the approach to PRA utilized in the PSA (the "PLG" methodology) and the one the NRC is more familiar with. The following discussion is provided to further clarify and enhance the reviewer's understanding of the PSA methodology.

In addition to the points raised in the second paragraph, there are very important aspects of the PLG approach to modeling dependencies that are not mentioned here. First, before the event trees are constructed, great emphasis is placed on the development of a firm understanding of the plant, its dependencies and interactions. This understanding is documented in the dependency matrices (Section 5.3.1) and the event sequence diagrams (Section 5.4) and reviewed with plant operations personnel long before the event/fault tree models that are derived from them are developed. It is correctly noted that the resulting sequences are presented differently. One key difference is the explicit representation of the dependent failures in the sequence descriptions. This serves to convey a more complete description of the sequence which pays dividends in reviewing the results and in performing the human reliability analysis.

Cut set information is contained in the PLG approach. The fourth paragraph of this section of the Draft Interim Report is incorrect in saying the PLG approach has no cut set or basic event representation. The cut sets and basic event representations are there, they are just packaged differently. PLG's methodology relies on "success paths" in block diagrams. The information contained in the block diagrams is manipulated as described in Section 4.2 of the PSA to produce the equation files contained in the PSA system descriptions (Volume 9). These equations contain the same logical information that is contained in a list of minimum cut sets. The systems analysis documentation includes equation files and cause tables that permit the identification of cut sets and basic event probabilities to the split fractions. The key difference is that cut set contributions to entire sequences are not provided. Such information can be generated, if it is needed, from information presented in the report.

There is a different philosophy behind the PLG approach that renders the cut set and basic information to be relatively less useful. Because of the more detailed representation of the accident sequences, experience indicates that opportunities for the development of engineering and risk management insights such as those developed in the PSA have been available without the extra analysis that would be needed to generate sequence level cut sets and importance measures. The characterization of the differences as "fundamental" is incorrect. The two methods are fundamentally equivalent.

SECTION 1.1 Continued

As noted, there are commonalities between the common cause data bases used in the PSA and NUREG-1150. However, it should be noted that the PSA common cause analysis followed NUREG/CR-4780 very closely, whereas NUREG-1150 did not. For example, NUREG-1150 did not screen the data base for applicability to the analyzed plants as called for in NUREG/CR-4780 and done in the PSA.

It is strongly concurred that both methods will produce correct results when applied properly.

Appendix 3: HLP Responses to Issues Raised During this Review

SECTION 1.2 - LIMITATIONS OF THE ANALYSIS

Exception is taken to some of the Limitations that are listed if the phrase "not treated here" is meant to be "is not treated in the PSA."

- Partial Failures - Some partial failures are modeled in the event trees and others are considered in the formulation of success criteria. There are other aspects of partial failures that are not considered.

- Design Adequacy - The probability that systems will not operate due to design adequacy is partially treated via the common cause analysis. The same is true with adequacy of procedures and similar parts related common cause. In fact, it is considered that the latter is treated to a high level of completeness in this PSA.

- Environmentally Related Common Cause - A great deal of effort was made in the spatial interactions task to treat this issue. Part of these are included in the common cause analysis.

It is agreed that no consideration was given to aging and sabotage. The break-in portion of the data base was partially removed in the component data base, however, so that the PSA results do not apply to the first few months to a year of operation.

Appendix 4: HLP Responses to HRA Issues Raised During this Review

SECTION 3.4.5 - STPEGS PSA HUMAN RELIABILITY ANALYSIS

The reviewers' thoughtful, in-depth comments on the human reliability analysis (HRA) methodology and documentation are well-taken. Many of the reviewers' comments pertain to issues related to the qualification, validation, and theoretical justifications for the PLG adaptation of the Success-Likelihood Index Methodology (SLIM). Although many of these concerns address broadly troublesome topics, it should be acknowledged that the same, or directly analogous, concerns have been voiced in many arenas about every contemporary HRA methodology. Indeed, the only uniform consensus among HRA/PRA practitioners is that no currently available methodology provides precise, theoretically verifiable, numerical predictions for human performance during the types of conditions typically modeled in modern PRA studies.

However, it should not be inferred from the preceding statement that it is a fruitless academic exercise to attempt the quantitative evaluation of human reliability. Consistent, quantitative estimates of human error rates and their associated uncertainties are a necessary and important part of any meaningful risk assessment. However, it is also vitally important to openly acknowledge the fact that, while it is very desirable to strive for "the" methodology that will accurately predict numerical human reliability estimates from qualitative information about human behavior, that methodology has yet to be discovered. The best that can be done is to ensure that the estimation processes that are used produce "reasonable" numerical results, account for the associated uncertainties, and do not contradict actual experience or informed expert opinion. That is, without deference, the current state-of-the-art in applied HRA.

A conscious decision was made not to encumber the PSA documentation with voluminous descriptions of the bases, background, and justifications for the methodologies applied in any part of the study. After consideration of the detailed response which could be elicited from the reviewer's comments in the Draft Interim Report (DIR), it is HL&P's judgement that an item-by-item written response to each concern raised in these review comments is not warranted at this time. In-depth discussion of the HRA methodology is scheduled for meetings on May 30 and 31, 1990. Any remaining concerns will be documented at the conclusion of those meetings and, if necessary, detailed written responses will then be prepared.

Appendix 4: HLP Responses to HRA Issues Raised During this Review

The following sections will briefly address some of the reviewers' more significant questions and concerns about the HRA methodology. These responses do not necessarily address each topic comprehensively or completely, but they will serve to focus the discussions at the May meeting.

It is agreed with the reviewer that any HRA methodology should allow an independent reviewer to reproduce the results, or to at least understand the process that was used to produce the results. Therefore, because the reviewers concur that the final PSA numerical human error rates (HER) are either somewhat conservative or are consistent with those produced by other methodologies, the questions that relate to "how we got from the beginning to the end" of the analyses will be addressed in the following sections. Responses are ordered according to the issues raised for each specific section of the STP PSA report.

SECTIONS 15.1 AND 15.2

It is considered that there are at least three significant advantages that have been achieved from the PLG adaptation of SLIM.

- Detailed documentation of operator input. The scenario evaluation sheets (e.g., PSA Tables 15.4-31 through 15.4-38) clearly document how each polled group of experts has assessed each human response scenario. It has been found that most plant operators feel more comfortable assessing the "degree of badness" for each performance shaping factor (PSF). This is one of the most significant reasons that lead PLG to transform the SLIM analysis to calculate a "failure likelihood index." Specifications of the H, M, and L weights also allows the operators to provide separate inputs to more carefully shape their assessment of each PSF. For example, no procedures may be available to guide a specific action; this would indicate a "relatively bad" rating of 10. However, there may be general agreement that the use of procedures for this activity is relatively unimportant; this would indicate a weight of L. Thus, the operators can provide quantitative and qualitative guidance for such traditional classifications as skill, rule, or knowledge-based behavior without being unduly confined to a set of rigid criteria and predefined categories. The tabular displays afforded by these evaluation sheets also ensure internal consistency among the assessments within each group of experts.

Observations of more than 25 expert teams have shown a uniform trend for each group to go through a "self-calibration" process during the early stages of the evaluations and to maintain subsequent consistency through continual cross-checking among their assessments. It should also be noted that after some initial skepticism, the evaluation process has received very enthusiastic support from licensed operating crews at several plants.

- Direct quantification of uncertainties. Variability of the assessments within each group of experts and variability of the assessments between groups are used directly to quantify the uncertainty in the numerical HER estimates. Thus, if all groups of experts are in close agreement about a particular action, the resulting numerical uncertainty distribution is relatively narrow; if there is a wide variation among the groups, the numerical uncertainty is correspondingly increased. The final HER uncertainty distributions are not arbitrarily constrained to a predetermined analytical form, and the uncertainty bounds are not simply assigned by a single HRA analyst after a point-estimate central tendency value has been calculated.

- Qualitative insights and identification of areas for improvement. The scenario evaluation sheets provide valuable information for plant engineers, trainers, and operators, regardless of the numerical HER values. Several changes have been made to plant instrumentation, controls, procedures, and training programs based only on reviews of the evaluation sheets. For HERs that are quantitatively important to the PSA results, the evaluation sheets provide a method for quickly identifying the most important areas for improvement (e.g., PSFs with numerical ratings and a weight of "H"). Estimates of the quantitative effects from proposed improvements can be made quickly by appropriately adjusting the affected PSF ratings.

The set of seven PSFs used for the PSA was adopted after a number of trials to determine an appropriate balance among concerns about completeness, independence of the PSFs, detail in identification of all possible influences, and evaluation efficiency. It is believed that the set of seven is a reasonable compromise among these attributes, and PLG is using this same set for all of its studies. In striving for completeness and detail in previous analyses, it was initially believed that "more must be better." PLG has tried (in one study) to use up to a total of 22 PSFs. Unfortunately, the PLG experience has shown that large numbers of parameters have two negative effects on the HRA results. The most important is that the experts became overwhelmed by the evaluation process, and the care and quality of their assessments is diminished.

A large number of PSFs would certainly provide somewhat better definition if only a few actions were being evaluated. However, a typical PRA contains 50 to 100 dynamic actions, and the enormity of the enumeration task causes most operators to quickly lose interest. Dividing the evaluation process among several separate sessions for each expert group is impractical, because it creates difficult scheduling problems and brings into question the internal consistency of the evaluations. A second effect noted from applying a large number of PSFs is a tendency for all actions to converge to a fairly small range of HER values. PLG has not investigated this phenomenon in detail, but the sense is that it is very difficult for experts to adequately express extremes in their opinions when a large number of parameters must be assessed.

The "operator response form" noted in PSA Section 15.2 is the "scenario sheet" that briefly describes the situation and the required action (e.g., PSA Tables 15.4-1 through 15.4-30). The experts are first briefed on the PSA models for the plant using the event sequence diagrams and their associated documentation. This briefing provides the context for each action and orients the experts to the analysis process. The "scenario sheets" are then used to prompt the experts to the specific conditions surrounding the action to be evaluated. Additional information may be supplied by a member of the PSA team who monitors each PSF evaluation session. However, extreme care is exercised to not unduly influence the experts' assessment by providing explicit or implicit clues about possible actions, available procedures, alarms, indications and other guidance/etc. The scenario descriptions must provide enough information for experienced personnel to understand what is happening in the plant when the desired action is requested. However, overspecification of the information tends to remind the experts about conditions that they may not otherwise consider, and it generally leads to more optimistic evaluations.

During the briefings prior to each evaluation session, it is requested that the group of experts try to reach a consensus value for each PSF rating and weight that they assign. This is reasonable, because a consensus will be reached during a real accident response scenario. (If there is a dominant individual to the group, this person will control the consensus opinions to both the evaluation process and during actual response). However, we also advise each group that irreconcilable differences should be noted in the "Remarks" column of the evaluation sheets with the corresponding values. (Although animated discussions often occur, significant lingering differences of opinion are quite rare.) The PSF ratings are varied during the HER quantification process, including any explicitly noted differences, to provide numerical estimates for each group's uncertainty. Variability among the estimates from all the groups is also explicitly used to quantify the composite uncertainty for each final HER probability distribution.

The LOTUS 1-2-3 program serves two principal functions during the HER quantification process. Simple spreadsheet sort and merge operations are used to compare the normalized PSF weights from each set of experts during the action grouping process. These functions allow the HRA analyst to efficiently examine similar patterns among the PSF weights and to assign individual actions to the appropriate groups. Rather than using such predefined categories as skill, rule, and knowledge-based behavior, the grouping process simply aggregates all actions that exhibit similar patterns in the PSF weights. In this manner, a typical population of 50 to 100 PRA actions is usually divided among approximately 3 to 8 groups of differing sizes. The second function performed by the LOTUS 1-2-3 program is a numerical analysis that determines a best-fit curve for the input calibration task index and HER values, calculates the "failure likelihood index" for each action being evaluated, and stores the corresponding point-estimate HER from the calibration curve.

SECTION 15.3

Many of the references for Section 15 of the PSA report were regrettably omitted. The HER values in PSA Tables 15.3-1 and 15.3-2 are based on the information in Tables 15-3 and 14-1, respectively, from Swain, A. D., and H. E. Guttmann, "Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications," NUREG/CR-1278, U. S. Nuclear Regulatory Commission, August 1983. The miscalibration HER distribution presented in PSA Figure 15.3-1 and Table 15.3-3 is taken from the analyses in Appendix D, Section D.6.3.2.2.2, and related Section 6.5 of the Seabrook PSA (Pickard, Lowe and Garrick, Inc., "Seabrook Station Probabilistic Safety Assessment," prepared for Public Service Company of New Hampshire and Yankee Atomic Electric Company, PLG-0300, December 1983).

RISKMAN is the name of the PLG proprietary software for the integrated analysis of data, systems models, and event trees. The RISKMAN designators mentioned on STP PSA page 15.3-2 are the database event names tabulated in the first column of Table 15.3-4. These event names are used to identify the corresponding HER distributions in the RISKMAN database and in the STP PSA system analysis equation files.

The designations in Table 15.3-4 are admittedly somewhat confusing and appear to have suffered from editing problems during production of the report. The reviewers have correctly deduced that the reference to Table 15-6 should instead be a reference to Tables 15.3-1 and 15.3-2. A second typographical error was made in the first entry labeled "ZHE01B" ("On completion of ECW...full-open position"). This entry should be labeled "ZHEOIA". The tabulated HER distribution for this entry is identical to the ZHEOIA HER distribution that is applied to three other entries noted in Table 15.3-4. The mean HER for designator ZHEOIA is 6.1E-03, and the mean HER for designator ZHEOIB is 9.4E-03.

Appendix 4: HLP Responses to HRA Issues Raised During this Review

Section 15.4

The event sequence diagrams and event trees documented in STP PSA report Section 5 are the basis for the full STP PSA plant model, including all dynamic human actions. These models were reviewed by the PLG PSA project team, the HL&P PSA project team, and STP plant operations and training personnel to identify and confirm the human actions.

No screening values were used to perform a preliminary ranking of the dynamic human actions in the PSA. As a result of the detailed reviews of the event sequence diagrams and event trees, actions were classified into two categories for quantitative analysis. Those actions judged to be important for the Level 1 core damage results, the Level 2 interfacing plant damage states, or for general understanding of event sequence progression were quantified using the detailed analysis methodology described in STP PSA report Section 15. All other potential human actions were left unquantified; that is, a failure rate of 1.0 was used as the effective screening value. This approach avoids well-documented problems from other quantification methodologies that result from the broad application of "conservative" HER screening values. These "conservative" estimates are often combined independently through the event model quantification logic to produce excessively optimistic estimates for the composite HERs within the full accident scenarios. The resulting sequence or cut set results are then eliminated from further examination, because they are subjectively characterized as being both "conservative" and "quantitatively insignificant."

The seven PSFs described in Section 15.2 are the final set used for the expert evaluations and the HER quantification.

The human action scenario sheets (e.g., PSA Tables 15.4-1 through 15.4-30) and the event sequence diagrams were given to the evaluation teams prior to each evaluation session. Each team also had available a full set of the STP plant drawings, all procedures, and the emergency response guideline background documents. The first portion of each evaluation session included one to two hours of training on the HRA evaluation methodology and probabilistic analysis. No formal debiassing training was performed. However, the results from the eight evaluation teams were thoroughly reviewed by the HRA analyst to check for possible biases. No uniform biases were observed. At least one member of the HRA team monitored each evaluation session. The HRA analyst answered selected questions about event sequence progression but did not supply information about postulated operator performance, procedures, alarms, etc.

Appendix 4: HLP Responses to HRA Issues Raised During this Review

The evaluations documented in STP PSA Tables 15.4-32 and 15.4-33 were performed early in the analysis process. These early sessions were planned to orient senior STP plant training and operations personnel to the evaluation process and to receive feedback on the human action scenario descriptions, information content, and possible problems to be anticipated when the control room operating crews were polled. As a result of comments received during these evaluations, some human actions were deleted from further consideration, and others were combined to form the final set of actions evaluated by the remaining teams.

For reference, missing PSA report page 15.4-73 is included with these responses.

The reviewers have correctly normalized the weights for the sample PSFs. The minor differences between the normalized values calculated by the reviewers and those published in STP PSA Table 15.4-38 arise from the application of an intermediate "fine tuning" step in the STP PSA calculation process. Unfortunately, this step was not documented in the PSA report. Some of the original PSF weights assigned by selected evaluation teams were annotated with "+" and "-" signs to indicate a finer range of definition than that afforded by the simple H, M, and L designators. The HRA team accounted for these expressed opinions by using a continuum of numerical weights between 0 and 10, rather than the three discrete values of 0 for L, 5 for M, and 10 for H as noted in the report. The "+" and "-" signs were also omitted from the affected weights when Tables 15.4-31 through 15.4-38 were published. The confusion created by these omissions is unfortunate and regrettable. However, as shown by the reviewers' calculations, the numerical impacts from these differences are quite minor.

The PLG HRA team assigned the PSF rating factors and weights for the calibration tasks. Unfortunately, scheduling constraints precluded the incorporation of these task descriptions into the full set of actions that were evaluated by each expert team. "Blind" evaluation of the calibration tasks by all the experts is certainly preferred to this method. However, STP PSA Tables 15.4-31 through 15.4-38 show that the PLG HRA team evaluations for the PSA actions were quite consistent with those team STP plant personnel. These results indicate that similar consistency would also be expected from the broader evaluation of the calibration tasks by all the expert teams.

Table 15.4-38 (Page 2 of 5). Shift E Operating Crew Evaluation

Human Action Identifier	Human Action Name	Performance Shaping Factors: Task Complexity	Indications and Plant Interface	Adequacy of Time	Preceding and Concurrent Actions	Procedures	Training and Experience	Stress	Remarks
HEOB03	Operator Performs Bleed and Feed	4 / L	3 / M	1 / L	3 / H	5 / M	8 / M	6 / M	
HEO3A	Operator Performs Bleed and Feed	4 / L	9 / H	1 / L	5 / M	5 / H	8 / L	6 / M	
HEOC01	Operator Starts Closed Loop RHR Cooling	8 / M	8 / M	7 / H	5 / H	5 / H	2 / M	5 / M	
HEOC02	Operator Starts Closed Loop RHR Cooling	8 / M	8 / M	7 / H	3 / L	5 / H	2 / M	3 / M	
HEOD01	Operator Cools Down and Depressurizes RCS	7 / M	8 / H	1 / L	3 / M	5 / H	3 / H	4 / M	
HEOD02	Operator Depressurizes RCS	5 / L	3 / H	3 / M	5 / M	9 / L	9 / L	8 / M	
HEOD03	Operator Cools Down and Depressurizes RCS	8 / H	8 / H	8 / H	8 / M	8 / L	9 / L	9 / H	

SECTION 15.5

All PSF weights for the recovery actions summarized in STP PSA Tables 15.5-18 through 15.5-20 were normalized according to the same methodology used for the analyses in Section 15.4. The correct normalized weights are displayed in the LOTUS 1-2-3 output in Tables 15.5-21 through 15.5-36. The numerical values displayed near the H, M, and L designators in Tables 15.5-19 and 15.5-20 were apparently copied from rough notes and were not deleted during the final report editing process. Although some of these values are, in fact, the correct normalized weights, all numerical values associated with the H, M, and L designators in Tables 15.5-19 and 15.5-20 should be ignored.

SECTION 15.6

STADIC is a PLG proprietary computer code that is used for probability distribution arithmetic and Monte Carlo sampling. It accepts input data in any type of probability distribution format, including discrete probability histograms. Algebraic equations that describe the desired combinations of these distributions are input by the user as FORTRAN subroutines. QDG is one of these subroutines that is used to calculate the unavailability of the emergency diesel generators as a function of their operating mission time after a loss of offsite power. STADIC is fully documented and has been verified according to PLG's quality assurance program. If desired, the STADIC user's manual can be provided to the reviewers for a more complete description of the code and its operation.

The analytical format of the electric power recovery model is expressed by STP PSA equations 15.6.1, 15.6.2, and 15.6.3. The "boundary conditions" from a specific event scenario determine the expected plant response and the associated time window that is available for AC power recovery (i.e., variable t). For example, if offsite power is lost at time t = 0 and all three diesel generators fail to start, different recovery time windows are defined by the status of the turbine-driven auxiliary feedwater pump and the positive displacement charging pump. Depending on the availability of steam generator makeup flow and reactor coolant pump seal injection flow, the amount of time that is available to restore AC power may be limited by the time for steam generator dryout, reactor coolant pump seal failure, or station battery depletion.

The tabulated probability distributions on STP PSA report pages 15.6-7, 15.6-8, 15.6-9, and 15.6-16 were input to the recovery calculations in their cumulative forms. As such, the tabulated probability values were assigned to the upper end of each value range. For example, for the table on page 15.6-8, the cumulative probability distribution shows a 20% probability value at a time of 0.5 hour, a 30% value at a time of 1.0 hour, and a 45% value at a time of 2 hours, etc. The probability density at intermediate times is obtained by differentiating the cumulative probability curve through these points.

Appendix 4: HLP Responses to HRA Issues Raised During this Review

The response time distribution tabulated on page 15.6-9 was developed by the PSA team after discussions with STP plant operations personnel, review of the STP emergency operating procedures, evaluation of typical and minimum required shift staffing, and actual walkdowns at the plant site. The statement on page 15.6-13 indicates that a detailed MAAP analysis could provide more refined estimates of plant thermal-hydraulic behavior and the associated recovery time windows for selected transients. However, it is also noted that no MAAP analyses were performed. All recovery time windows were defined by applying straightforward mass and energy balance calculations as described in Section 15.6.4.1.

Appendix 4: HLP Responses to HRA Issues Raised During this Review

RESPONSES TO NRC HRA ISSUES

Section 3.4.5 Human Factors

General

1. Since the STP PRA used a unique Human Reliability Analysis (HRA) Methodology which is a variation of three other methodologies (SLIM, SHARP, and THERP) more documentation (in summary form) should be provided. This documentation should include: a summary of the deviations from the three original methodologies, justification for these deviations, and references for the three documents.

Reply:

The THERP methodology for human error rate estimation was not directly applied in the South Texas PSA. Tabulated values and dependency correlations from NUREG/CR-1278 (Reference A4-1) were used as references for system-level human errors that may leave equipment disabled during normal plant operation. These errors may occur during a variety of activities that involve normal equipment testing, maintenance, inspection, and calibration. The tabulated error rate distributions are presented in the South Texas PSA, Section 15.3. It is today generally acknowledged that the error rate estimates from NUREG/CR-1278 are better suited to these types of routine procedure-directed activities than the dynamic responses that occur after an initiating event. The detailed THERP logic modeling process was not applied to each system-level procedure. This process is quite time-consuming and mechanistic. The system analysts evaluated each testing, maintenance, inspection, and calibration procedure in the context of the plant hardware configuration and personnel to identify the most important activities that could leave a piece of equipment disabled and undetected. The tabulated error rates were then applied for these critical actions.

The principles of SHARP (Reference A4-2) were used to guide the qualitative identification and representation of dynamic human errors in the event sequence diagrams and event trees. The methodology description in Section 15.2 briefly notes the relationship between the South Texas PSA dynamic action modeling activities and the seven formalized steps of SHARP. It should be noted that the modeling process used for this study combined some of the SHARP steps and simplified others. Step 1, Definition, is performed during the development and documentation of the event sequence diagrams. Step 2, Screening, was effectively eliminated in its traditional, quantitative sense. Qualitative decisions were made about each prospective human action in the event model. If an action was determined to be significant for understanding plant response, affecting core damage, or influencing a plant damage state, that action was modeled in detail and quantified according to the methodology described in

Section 15.2. If an action was deemed to be unimportant to the study, it was not modeled. No non-unity, numerical screening values were used to simplify the quantification process. Experience has shown that careless application of this step in SHARP can inappropriately suppress important actions or subtle dependencies from further analysis. Step 3, Breakdown, is performed in the translation from the event sequence diagrams to the event tree top events and the corresponding scenario description forms used in the operator assessment process. Step 4, Representation, and Step 5, Impact Assessment, are documented in the event tree model structure, the definitions of each human action top event, and their corresponding split fractions. The event trees provide the formal logic model for representing each action and its impact on subsequent system performance or human responses. Step 6, Quantification, is described in Section 15.4 of the report. Step 7, Documentation, is accomplished by the combination of the event model documentation in Section 5 and the human reliability analysis documentation in Section 15.

The SLIM quantification methodology (Reference A4-3) has been modified as described in Section 15.2. The most important changes are the format used to document the expert assessments, the use of a predefined set of seven performance-shaping factors, and the "inversion" of the process to calculate a "failure likelihood index." These changes were made to improve efficiency in the expert elicitation process, to develop an index that is more easily related to the likelihood of failure, to facilitate consistent quantification of uncertainty in the resulting human error rates, and to clearly display the important contributors to each error rate and its associated uncertainty distribution. The attached paper (see Appendix 5) was presented at the 1988 IEEE Fourth Conference on Human Factors and Power Plants (June 5-9, 1988, Monterey, California). It captures the essential changes in the SLIM methodology in a more summary format than is presented in Section 15.2 of the South Texas PSA report.

Sections 15.1 and 15.2

1. SLIM is broken into steps. The variation of SLIM used by the STP included a step one, that was an adaptation of steps one and two of SHARP. Provide more information on what was used from the two steps of SHARP and why this was considered desirable.

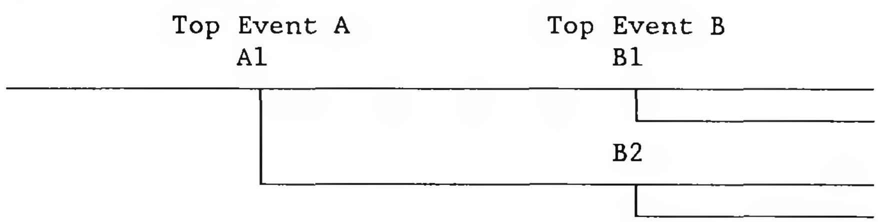
<u>Reply:</u>

The first step in the modeling process is based on the guidelines described in Step 1 of the SHARP methodology. This step identifies the important human actions that may affect event sequence progression, core damage, or plant damage states. This step is performed during the development and documentation of the event sequence diagrams presented in Section 5 of the South Texas PSA report. Step 2 of SHARP was effectively eliminated in its traditional, quantitative sense. Qualitative decisions were made about each prospective human action in the event model. If an action was determined to be significant, that action was modeled in detail and quantified according to the methodology described in Section 15.2. If an action was deemed to be unimportant to the study, it was not modeled. No non-unity, numerical screening values were used to simplify the quantification process. Experience has shown that careless application of this step in SHARP can inappropriately suppress important actions or subtle dependencies from further analysis.

2. Provide a definition of a split fraction failure criteria.

Reply:

A split fraction is the value assigned to a top event at a particular location in the event tree structure. In the simple event tree below, Top Event A has one split fraction, A1, and Top Event B has two split fractions, B1 and B2.



In general, the success (or failure) criteria for Top Event B depends on the status of Top Event A. Thus, split fraction B1 evaluates the likelihood that B succeeds (or fails), given success of A; split fraction B2 evaluates the likelihood that B succeeds (or fails), given failure of A. If, for example, Top Event B models an operator action and Top Event A models a system that affects the amount of time available, the value for B may be quite different, depending on whether A succeeds or fails. The basic concept of split fractions is discussed in the methodology section (i.e., Section 4.1) of the STPEGS PSA report.

3. The scenario sheet form is used to implement step four of the adapted SLIM methodology. It is implied in the documentation that this form is an adaptation of step three from SHARP. However, SHARP documents operating experience and influence parameters as a major portion of the step. Step four of the adapted methodology doesn't include either. Provide an explanation for this.

Reply:

It has been noted that several of the formal steps in SHARP have been reorganized to facilitate a more systematic progression from event model development through identification of detailed human response scenarios and, finally, definition of the specific actions to be quantified.

Insights from operating experience are used to define the human actions and their interdependencies during the development of the event sequence diagrams and event trees described in Section 5 of the STP PSA report. The fundamental elements of Step 3 in the SHARP methodology are implemented during the translation from the somewhat generally defined operator actions in the event sequence diagrams to the explicitly defined top events and split fractions in the event tree models. Important physical, functional, and cognitive dependencies are identified during this step of the process, and separate top events or split fractions are defined to coherently represent these dependencies within the resulting event sequences. The scenario description forms then document the event progression, required actions, and the major factors that influence operator response for each split fraction.

4. Provide additional information on the thermal hydraulic analysis that was used to determine the approximate time windows.

Reply:

Thermal-hydraulic analyses were performed to determine the available operator response times for various preceding sequences of events. For example, during a station blackout, the amount of time available to restore electric power depends on the rate of steam generator dryout and the rate of reactor coolant pump seal degradation. These rates, in turn, depend on the availability of steam generator makeup flow and seal cooling flow. The thermal-hydraulic analyses use information on preceding system successes and failures to determine these rates and the corresponding operator response time windows. Section 12 of the STP PSA report describes the room heatup and thermal fragility analyses that were performed for loss of HVAC event scenarios. Section 15.6 presents the supporting documentation for the offsite and onsite electric power recovery analyses. Appendix B of the report summarizes all other thermal-hydraulic analyses that determined operator response time windows.

5. A descriptive scaling guide was developed for each of the Performance Shaping Factors (PSFs). Provide information on the history of this development, i.e., how the guides were developed, who was involved, and how the guides were utilized in the analysis.

Reply:

The descriptive scaling guides provide an initially consistent frame of reference for the experts' PSF ratings. These guides have evolved through application of the methodology at several plants, and they are usually modified slightly for each new PRA. They were developed by PLG analysts in response to early requests by operators who needed an aid for translating their qualitative understanding of a situation into a numerical rating factor. As part of the early interactions with senior members of the South Texas operating and training staffs, the scaling guides were reviewed to ensure that they could be easily understood by the plant operating crews. Minor adjustments in the conditions and wording were made at the direction of these senior plant personnel. During each expert elicitation session, it was emphasized that the guides are simply tools to help the experts gain an appreciation of the relative numerical rating values. It was emphasized that 0 means "as good as it can be," 5 means "average," and 10 means "as bad as it can be." It was also stressed that the specific statements in each guide are not to be interpreted as perspective criteria for a particular numerical value. In practice, most experts initially review the guides and then quickly abandon them when they understand the rating process. Through a continuing process of "self-calibration," each group develops a consistent interpretation of the relative value for each numerical rating factor. Observations of several groups have shown a nearly uniform tendency to adjust specific PSF ratings across several actions as the group gains greater appreciation of the numerical assessment process. In this manner, the PSF ratings for all actions become internally consistent. This allows the failure likelihood index values to provide a consistent measure of the "relative difficulty" for each action, which is a primary goal of this stage of the analysis. Thus, the scaling guides are used as a convenient set of references to start the evaluation process, but they do not have a strong influence on the final results.

Section 15.3

1. With respect to certain critical human error probability (HEP) data (such as miscalibration of level sensors) documented in Appendix D of the South Texas PRA, reference has been made to those HEPs developed in the Seabrook PRA. Provide discussions related to the applicability of the HEPs of the Seabrook PRA (based on the above example).

<u>Reply:</u>

The Seabrook plant is a four-loop Westinghouse PWR of a design contemporary to that of STPEGS. Calibration of equipment at STPEGS is performed individually with similar procedures and frequencies to that of Seabrook so that the occurrence of calibration errors would be expected to be similar. However, and of greater importance, on STPEGS there are up to four devices that must be calibrated instead of two or three as onSeabrook. All four devices must be miscalibrated for a system failure to occur. The STPEGS modeling has been very conservative in adopting the same approach as Seabrook in that a moderate dependence exists between the first and second act of calibration. All subsequent acts of calibration are then assumed to be totally dependent, i.e., if the second instrument is miscalibrated given that the first was also miscalibrated, then all will be miscalibrated.

The analyst who evaluated the South Texas instrumentation systems was also very familiar with the Seabrook analyses. After a review of the South Texas instrumentation hardware, its configuration, and the calibration procedures, it was determined that the Seabrook results were simply referenced for expedience rather than reproducing the entire analysis in the South Texas documentation.

Section 15.4

1. The PSFs were evaluated using H, M, and L ratings. Provide a discussion on the criteria used to determine which rating was appropriate for a PSF. Also, include information on how the rating system was developed and its advantages.

<u>Reply:</u>

During each evaluation session, the experts are asked to quantitatively <u>rate</u> each PSF for its contribution to successful performance of the required action. These numerical ratings are assigned on a scale from 0 to 10 for each PSF. The experts are also asked to qualitatively assess the <u>importance</u> of each PSF during the specific action scenario being evaluated. These PSF weights are designated H (extremely important), M (average importance), and L (not important). The experts assign these weights based on the group's consensus opinion in the same manner as they assign the numerical rating factors.

Rather simple qualitative values of H, M, and L were selected for the PSF weights to reduce the experts' burden during the evaluation process. Although it may seem desirable to provide a numerical scale for these weights in the same manner as the PSF ratings, limited attempts to do this have met with poor success. The experts typically must evaluate between 50 and 100 different actions, and many control room operators are quite unfamiliar with numerical analysis techniques. The assignment of two sets of numerical values for each PSF overwhelms most participants and reduces the overall effectiveness of their evaluations. Retaining numerical values for the ratings and alphabetic values for the weights also reinforces the fact that the experts must consider different factors (influence versus importance) when they perform their evaluations.

The use of these PSF weights enhances the quantification processes by providing more information about the experts' understanding of what most strongly influences operator response. For example, it may be determined that no procedures are available to guide a particular action. The numerical rating for the Procedures PSF in this case should be 10. However, the experts may also know that this type of action is not strongly influenced by procedures; e.g., it may be skill- or knowledge-based. Assignment of a weight of L to the PSF conveys this information to the human reliability analyst and reduces the importance of the procedural deficiency in the final results. Obviously, PSFs that receive a numerical rating of 10 and weight of H have extremely important effects on the operator error rate.

The PSF weights also facilitate grouping of the actions within similar functional categories. The pattern of PSF weights is a type of "signature" for the action that is analogous to the more restrictive skill-, and knowledge-based categories used in other methodologies. Different actions having similar patterns of PSF weights can be combined within the same functional group to enhance the application of calibration tasks and to reduce uncertainty in the human error rate estimates across the full spectrum of actions evaluated.

Section 15.6

1. Provide discussions related to the development of a time-dependent cumulative probability distribution function used to characterize the recovery of the South Texas grid and the repair and/or restoration of the onsite diesel generators.

Reply:

Offsite Power Recovery

The South Texas offsite power recovery distribution is shown in Figure 15.6-1 of the PSA report. This distribution was derived from historical forced outage data from 138-kV and 345-kV transmission lines in the interconnected Central Power & Light (CP&L) grid. The same methodology has been used for offsite power recovery analyses in nearly all of the PLG PRA studies, including Zion, Indian Point, Midland, Seabrook, and several others not currently in the public domain. This experience has shown that the use of actual outage data from the grid surrounding a particular site can have a measurable influence on the likelihood for offsite power recovery as a function of time after a loss of offsite power event. The most important factors that affect power recovery are often outside the direct control of the nuclear power plant, its operators, and its managers. These factors include the regional geography and meteorology; the design of the surrounding grid and its protection systems; automatic, remotely controlled, and local manual switching requirements; personnel availability and emergency response policies for the interconnected utilities' transmission and distribution departments; etc. Historical forced outage data provide the best available measures of the composite effects from all these factors. Thus, for example, a remote rural grid in an area subject to severe summer and winter storms will generally exhibit longer restoration times than a suburban grid in a relatively mild climate.

The process for developing the distribution shown in Figure 15.6-1 is relatively straightforward. The transmission line forced outage data from 1982 through 1986 were first sorted by duration to develop a conditional frequency distribution for the fraction of line outages as a function of repair time, i.e., a curve that plots the cumulative fraction of all forced line outages that were restored at successful time intervals. This curve formed the basis for the final probability distribution as follows.

Two hypotheses were formulated regarding the relative independence of the nine transmission lines connected to the South Texas switchyard. The first hypotheses assumed that all circuits would behave as if they were fully coupled during a complete loss of offsite power. This is a very pessimistic assessment, but it accounts for conditions such as extremely severe weather, unexpected transient load instabilities, unidentified coupling among protection relaying networks, etc. This "single line" possibly was assigned as the 5th probability percentile for the final offsite power recovery distribution. In other words, a 95% probability was assigned to the likelihood that actual offsite power recovery at South Texas would be better than indicated by a fully-coupled "single line" model. The collected data from single line forced outages formed the time distribution for this 5th probability percentile curve.

The second hypotheses assumed that the offsite power circuits would exhibit a degree of independence during recovery efforts after a complete loss of offsite power. Reviews of data from several utilities have often shown relatively high coupling among transmission circuits that are routed on a common right-of-way. This coupling can often be traced to the common physical orientation of the lines for wind loading, the fact that they terminate at the same switching stations, etc. Based on this experience, the second hypotheses assumed that the South Texas circuits would behave as if they were three fully independent transmission lines, corresponding to the three major rights-of-way at the site. This "three line" possibility was assigned as the 95th probability percentile for the final offsite power recovery distribution. In other words, a 95% probability was assigned to the likelihood that actual offsite power recovery at South Texas would be worse than indicated by a completely independent "three line" model. Three sets of the collected data from single line forced outages were combined independently to form the time distribution for this 95th probability percentile curve.

A normal probability distribution was defined by the assigned 5th and 95th percentile curves. Finally, the recovery fraction values were inverted (i.e., subtracted from 1.0) to obtain the "nonrecovery" distribution shown in Figure 15.6-1.

Two additional comments are worth noting with respect to this formulation. The first is that HL&P currently has formal agreements with the owners of the South Texas Project Electric Generating Station that assign high priority to restoration of offsite power to the South Texas site (reference HL&P Letter to the NRC, ST-HL-AE-3408 dated April 5, 1990). These agreements were not in force when the PSA analysis was performed, and they have not been considered in the models. The second comment relates to the "generic" offsite power recovery data plotted in Figure 15.6-1. These data are simply displayed in the South Texas PSA as a reference for "average" industry experience that has been tabulated by the Electric Power Research Institute. The type of simple numerical averaging used to produce these "generic" curves does not accurately reflect the extreme variability of experience among the various sites.

This observed variability and the associated uncertainties in the predicted response at a particular site are the fundamental reasons for developing the South Texas site-specific model described in Section 15.6.

Diesel Generator Recovery

The South Texas diesel generator recovery distributions are shown in Figures 15.6-2, 15.6-3, and 15.6-4. These distributions are based on the model and data described in Section 15.6.3.2. Two fundamental input distributions for these models are the operator response time distribution summarized on page 15.6-9 and the diesel generator repair time distribution summarized on page 15.6-8.

The operator response time distribution was developed subjectively after discussions with South Texas operations personnel, reviews of normal shift manning requirements, and plant walkdowns to establish typical transit times to the diesel generator building from the control room and local operator stations. Plant communications and security systems were also checked to confirm continued ability to notify plant personnel and to gain access to the diesel generators after a loss of all AC power.

The diesel generator repair time distribution was developed from a combination of actual diesel generator repair data that has been collected from several plants and a subjective assessment of the availability of maintenance personnel. The repair data were used to develop estimates for the time required to correct a wide variety of problems typically encountered during diesel generator functional testing. Most of this experience has been collected from relatively routine repairs that are conducted within the time limitations imposed by the plant technical specifications. Although there is a degree of urgency associated with the restoration of any safety-related component, these routine conditions are certainly not the same as those during an actual emergency. Therefore, the historical repair time data available from normal plant operating experience are quite likely to be conservative estimates for repair times that would be observed during a loss of all AC power. The availability of maintenance personnel to perform the various types of possible repairs was subjectively assessed after discussions with South Texas maintenance and management personnel. The repair time data and personnel availability information were combined subjectively to produce the composite repair time distribution shown on page 15.6-8.

2. Provide discussions regarding the probability distributions associated with the tables on recovery actions, pages 15.6-7, 15.6-8, 15.6-9, and 15.6-16.

Reply:

The tables on pages 15.6-7, 15.6-8, 15.6-9, and 15.6-16 present ranges of possible values to avoid an inappropriate overstatement of confidence that would be implied by the use of precise single values. For example, the proper interpretation of the table on page 15.6-8 is that there is a 20% probability that diesel generator will be repaired within the first half hour after operator response, a 10% probability that it will be repaired within the next half hour, a 15% probability that it will be repaired within the next hour, etc. All probability distributions are input to the quantification process in cumulative form, which is the piecewise linear sum of the noted elements. This cumulative form is fully specified and is not ambiguous. For the table on page 15.6-8, the following is the cumulative probability distribution:

Time Following Operator Response (hours)	Cumulative Probability of Recovery
0	0
0.5	.20
1.0	.30
2	.45
4	.60
8	.80
24	.90
∞*	1.00

*Set equal to 100 hours for actual quantification.

The cumulative form of the operator response time distribution shown on page 15.6-9 is as follows.

Response Time (minutes)	Cumulative Probability
0	0
5	.01
10	.26
15	.76
20	.96
30	.99
60	1.00

The reactor coolant pump seal LOCA flow distribution summarized in Table 15.6-1 (page 15.6-16) is somewhat more difficult to interpret. (One difficulty may arise from a typographical error in the fifth time interval column. The published column heading is 4.5-5.5 hours; the correct heading should be 3.5-5.5 hours.) For example, the first line in the table indicates that a probability of 0.2712 was assigned to the condition that total seal leakage flow from all four reactor coolant pumps increases immediately to 84 gpm after loss of all seal cooling and remains constant at this value. The second line assigns a probability of 0.0151 to the condition that total seal leakage flow immediately increases to 84 gpm and remains constant until 2.5 hours after the loss of cooling; at 2.5 hours, the leakage flow increases to 244 gpm and remains constant thereafter. The sixth line assigns a probability of 0.0059 to a condition with five stepwise increases in flow: an immediate increase to 84 gpm for 1 hour; an increase to 244 gpm for the next 1/2 hour; an increase to 433 gpm at 1.5 hours, remaining, constant until 3.5 hours; an increase to 480 gpm at 3.5 hours; and a final increase to a steady-state value of 698 gpm at 5.5 hours. Stepwise increases in the seal leakage rates were used at discrete times to simplify the model. All increases occur at the specified transition time. Thus, for example, in the second line from the table, flow increases to 84 gpm at exactly 0 minutes after the event (i.e., at event initiation) and remains at this value until just before 2.5 hours; flow then increases to 244 gpm at exactly 2.5 hours after the event. The application of this seal leakage model is discussed in Section 15.6.4.1. It is derived from the expert elicitations supporting the reactor coolant pump seal LOCA analysis for NUREG-1150 (Reference 15-5 in Section 15.7 of the STP PSA report).

References:

A4-1 Swain, A. D., and H. E. Guttmann, "Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plan Applications," NUREG/CR-1278, U. S. Nuclear Regulatory Commission, August 1983.

A4-2 Hannaman, G. W., and A. J. Spurgin, "Systematic Human Action Reliability Procedure (SHARP)," NP-3583, Electric Power Research Institute, June 1984.

A4-3 Embrey, D. E., P. Humphreys, E. A. Rosa, B. Kirwin, and K. Rea, "SLIM-MAUD: An Approach to Assessing Human Error Probabilities Using Structured Expert Judgement," NUREG/CR-3518, U. S. Nuclear Regulatory Commission, March 1984.

Appendix 5: Quantification of Human Error Rates Using a SLIM-Based Approach

Appendix 5 contains a paper presented at the 1988 IEEE Fourth Conference on Human Factors and Power Plants in June of 1988 in Monterey, California. The paper presents details on the changes in the SLIM methodology used for the STP PSA.

QUANTIFICATION OF HUMAN ERROR RATES USING A SLIM-BASED APPROACH

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Abstract

This paper presents an application of the success likelihood index methodology (SLIM) [1, 2, 3] for quantifying dynamic scenario-related human actions for use in a PRA. The application has been structured to make the assumptions, bases, and calculations leading to the quantitative evaluation of human error rates under plant transient conditions both scrutable and useful for use in risk management. It provides a structure in which assessment teams of operators and PRA analysts can provide feedback on the problems operators face and a means to prioritize corrective action. The utility of this procedure is expected to improve as the forms are updated to reflect the experience of previous applications and it is applied to a variety of situations.

Overview of SLIM

The success likelihood index methodology (SLIM) was developed under the sponsorship of Brookhaven National Laboratory and the U.S. Nuclear Regulatory Commission [1, 2, 3] to quantify operator actions in the plant response model of a probabilistic risk assessment. It is based on the assumption that the human error rate in a particular situation depends on the combined effects of a relatively small set of performance-shaping factors (PSF) that influence the operators' ability to perform the action successfully. PSFs account for both the plant conditions, or scenarios, under which the action must be performed and the psychological and cognitive state of the individuals performing the action. An example of a scenario-related PSF is the adequacy of time available to accomplish the action, while a psychological and cognitive PSF might address training and experience relative to the required action. The quantitative evaluation of the human error rate for the action is accomplished by judges who are assumed to be able to rank the PSFs in two ways:

- A numerical rating, r_i, of the degree to which the PSF helps or hinders the performance of the action.
- A ranking of the relative importance, or weight, w_i, of each PSF for influencing the reliability of the action.

An important assumption of SLIM is that the expert judges can select an appropriate set of PSFs and accomplish these two rankings independently of each other.

Once the ratings and weights have been obtained, a numerical success likelihood index (SLI) that represents the overall belief of the judges regarding the positive or negative effects of the PSFs on the likelihood of success for the action is calculated in accordance with the relation,

$$SLI = \sum_{i=1}^{I} w_i r_i \tag{1}$$

This numerical index is converted to a success rate for the action by assuming that it follows the relationship

$$\log_{10}(\text{success rate}) = a(SLI) + b \tag{2}$$

where a and b are calibration constants obtained by evaluating calibration tasks having "known" or "accepted" error rates in a similar manner. The basis and justification for the SLIM methodology are given in detail in References 1 through 3.

Summary of Application Features

This paper describes how the concepts of SLIM have been structured to facilitate the elicitation of expert opinion from plant operators and engineers for use in probabilistic risk assessments and risk management. The major features of this structure are:

- A set of seven predefined PSFs selected to span the spectrum of influences that might affect the operator's ability to accomplish the action.
- A set of forms to organize and document the information required to rate the action and its seven performance-shaping factors. These forms provide a qualitative assessment of the problems the operators may face while accomplishing the action.
- A rating scale that increases as the likelihood of failure increases. The ratings are then transformed into a failure likelihood index (FLI) in accordance with a relation that parallels Equation (1).

$$FLI = \sum_{i=1}^{I} w_i r_i \tag{3}$$

Use of a larger rating for increasing failure likelihood permits a direct ranking of the contributors to human error. A large weight coupled with a high rating combines to make a large product, indicating a dominant contributor to the human error rate (HER).

Once the FLI has been determined, it is converted into an HER using a formulation that parallels Equation (2).

$$\log_{10}(HER) = a(FLI) + b \tag{4}$$

- A Lotus 1-2-3 spreadsheet that can calculate the calibration constants a and b in Equation (2) and use them to determine the HER of actions from the ratings of the assessment team.
- A Lotus 1-2-3 spreadsheet that displays a ranking of contributors to the human error rate. This ranking is accomplished by multiplying the weight of the PSF by the numerical rating of the PSF by the assessment team.

Because the rating increases as the failure potential increases, the product of the weight and the rating becomes a direct measure of the relative contribution of that PSF to the human error rate of that action.

Implementation

Operator actions are selected for quantification by reviewing the plant event sequence diagrams and event trees to identify operator actions that impact plant risk. This process generally follows the methodology outlined in steps 1 and 2 of SHARP [4]. The definition of the operator action must consider the split fraction failure criteria for the scenario in which the action takes place.

A set of seven performance-shaping factors that address a spectrum of influences affecting operator actions has been defined. These seven PSFs cover most conditions the operator is expected to encounter. However, other PSFs may be used if warranted by the situation.

- **Plant Interface and Indications of Conditions.** This PSF relates the impact of the man-machine interface on the likelihood of success. It measures the degree to which the control room or the local conditions at the time when the action must be accomplished assist or hinder the operator in performing the action.
- **Significant Preceding and Concurrent Actions.** This PSF addresses the context of the modeled action. Preceding and concurrent actions can assist the action if they make it necessary and obvious to the operators. They can also divert the operators' attention from this action and cause a dependent failure. Lack of preceding actions may create a surprise effect that should be accounted for in this PSF.
- **Task Complexity.** This PSF rates the effect of multiple requirements on task success. It can range through the entire gamut of considerations to include coordination, multiple locations, remote operations, variety of tasks, and communications requirements. It also accounts for the availability of resources.
- **Procedural Guidance.** This PSF accounts for the extent to which plant procedures enhance the operator's ability to perform an action. The operator may have available not only step-by-step instructions, but also guidance on when the action has been correctly done.
- **Training and Experience.** This PSF measures the effect of the familiarity and confidence the operators have about the action. It accounts for the similarity of the action to previous operating transients. It also considers the frequency and depth of simulator and classroom training as it relates to this specific action.
- **Adequacy of Time to Accomplish Action.** This PSF considers the time required to complete the action compared with the time available and the effect on success. The rating reflects the confidence that the task can be accomplished in time to avert a change to a failed state. Depending on the definition of the action, the time required may include both the time required to diagnose the problem and the time to physically accomplish the action. The time available would then be measured from the first indication available to the operator.
- **Stress.** This PSF accounts for situations that may endanger the operator, damage or contaminate either the plant or the environment, or result in a long plant outage. Depending on its level, stress can serve as an incentive to accomplish the action, produce a reluctance to do it, or provide a diversion of attention that increases the likelihood of failure.

Each significant action is qualitatively evaluated on an operator response form designed to systematically lay out the context of the action, the cognitive tasks required to accomplish it, and those factors that influence the operator's ability to successfully accomplish it. This step is very similar to step 3 of SHARP [4]. Table 1 is a checklist that guides the completion of the form. It consists of three parts.

- Section A defines the action and establishes its context. It explicitly defines the tie between the plant risk model and the operator action being evaluated. The scenario up to the point at which the action is required provides the context. The split fraction failure criteria and time available define the plant state that will result from the operator's failure to accomplish the action and the estimated time available for the operator to act before the plant goes into that state. The time available is obtained from estimates of the rates of the physical processes invdlved.
- Section B breaks down the action into its cognitive elements. A cognitive element is a group of steps that can be completed before an operator must pause to obtain feedback from the plant or consider what to do next. This section explains how the action is accomplished with enough detail to identify potential problems. It is not necessary to list every step in the procedures the operators follow, but it is necessary to provide enough details, with references to procedures, to assist the evaluation team in identifying those performance-shaping factors that will influence the success or failure of the action.
- Section C summarizes how the PSFs influence the success or failure of the action. This section provides an opportunity to describe potential problems the operators might face while accomplishing the action. It can also delineate those things that can assist the operators.

The forms are most effective when they can be completed with active interaction with at least one senior reactor operator. The intent of the form is to accurately relate the problems the operators are expected to face if an accident scenario progresses to that point. The forms may be updated throughout the evaluation to reflect the insights of the evaluation teams. They improve the scrutability of the rating and can also provide suggestions for improving the procedures, training, or plant design.

Assessment teams consisting of operators and PRA team member quantitatively evaluate the actions. To make the process effective, the operators must understand that they are not being evaluated. Rather, the assessment is their opportunity to communicate the problems they face and provide suggestions for improving their ability to respond to the situation.

A set of descriptive scaling guides has been established to assist the rating of each PSF. An example of a scaling guide is given in Table 2. They are used as a reference to assist experts with different backgrounds in maintaining a consistent rating basis.

The descriptors on each scale are positioned to conform with the following general quantitative guidance for PSF ratings:

- A 0 corresponds to this PSF being "optimum" for assisting the operator team to accomplish the action in question.

Table 1. Guidelines for Completion of the Operator Response Form

HUMAN ACTION IDENTIFIER: ____________ TOP EVENT: ________

HUMAN ACTION NAME: ____________

A. GENERAL DESCRIPTION

1. **Action Required** Briefly state the action in general terms.

2. **Scenarios in Which Action Occurs** State the broad context of the action. Identify initiating events and the previous response of the plant. Describe variations in the scenario that can affect the likelihood of success: e.g., system failures, previous operator errors, and conditions that could impact available time.

3. **Time Window Available** State the physical or operational bases for time limitations the operator faces. Reference source of bases. Identify the plant change of state that indicates the end of available time.

4. **Split Fraction Failure Criteria** Explicitly define the outcome of failing to accomplish the action correctly. Explicitly define boundary conditions to be evaluated. Objective is to succinctly summarize what is quantified.

B. TASK ELEMENTS

Provide sufficient detail to give a good picture of action, but it is not necessary to repeat every procedural step.

Task	Equipment	Location	Time Required	Comments

C. EVALUATION OF PERFORMANCE-SHAPING FACTORS

1. **Plant Interface and Indications of Condition.** Availability of alarms, instruments, and trend indications. Location of indications relative to required action. Quality of information: direct indication or interpretation required? Competing alarms and potential for confusion. Feedback to operator on correctness of response.

2. **Significant Preceding and Concurrent Actions.** Focus on required action or diverts attention? Is action expected or a surprise? Priority of action relative to other actions.

3. **Task Complexity.** Variety of subtask types and locations. Determine the level of cognitive process as skill, rule, or knowledge based. Number and qualifications of people required. Communications and coordination required. Potential demands on resources at time of action. Accessibility to the required plant equipment.

4. **Procedural Guidance.** Are they memorized or must they be read? How specific and applicable to this action? Assist in both diagnosis and response? Impact of EOPs on response. Existence of other supportive or conflicting guidance.

5. **Training and Experience.** Describe simulator training similar to action. Frequency of talk-throughs/walk-throughs on this action. Classroom or academic training. Similarity of training or experience to required action.

6. **Adequacy of Time To Accomplish Action.** Judge time available (Section A.3) relative to time required to complete (Section B, Time Required). Estimates by operators. Observations of simulator training.

7. **Stress.** Noise, vibration, radiation level, humidity, temperature, lighting, and other environmental stresses. Level of alertness at time of action (surprise factor). Perceived time available. Perceived threat or consequences. Toxic substance around working environment.

8. **Other.** List specific criteria.

- A 5 corresponds to conditions that neither significantly help nor hinder the performance of the action.
- A 10 corresponds to a condition when this PSF is hindering the performance of the action to the greatest extent possible.

The final group rating is obtained by consensus. Reasons considered in arriving at a consensus are recorded on the operator response form.

When the ratings of the actions have been completed, they are compared for consistency. Since human error rates will be calculated on the basis of these relative ratings, this review and update are essential.

The next step weighs the relative importance of the PSFs. The weight of a PSF relates the degree to which a change in the numerical rating of the PSF scale changes the operator's ability to accomplish the action. A PSF will have a large weight when a small change in the rating may produce a large change in the failure likelihood index. Conversely, if a large variation of the PSF rating scale has little impact on the likelihood of failure, the PSF will have little or no weight in determining the failure likelihood index. The relative weights of the PSFs affecting an action can be estimated by judging how much the rating of one PSF would be increased (made worse) to offset a decrease in the rating of another PSF by some convenient amount. Once the relative PSF weights are established, they are normalized to sum to 1.

When the weights have been established, the operator actions are classified into groups so that actions having similar PSF weights can be quantified together. The PSFs in different groups will have different normalized weights. However, within each group, only one set of normalized weights that is representative of the entire group will be used. This set can be obtained by averaging the weight of each PSF over the group or by reevaluating the PSFs considering the group as a whole. PSFs that are judged to have no significant influence on the likelihood of success of the group can be given a weight of zero.

Table 2. Performance-Shaping Factors and Scaling Guide

PSF. Significant Preceding and Concurrent Actions

Preceding and concurrent actions set the stage for the modeled action. They can assist the action if they make it necessary and obvious to the operators. They can also divert the operators' attention from this action or even cause failure. (If necessary, some strongly dependent failures may be accounted for by specific split fractions in the event trees.) Lack of preceding actions may create a surprise effect that should be accounted for in this PSF.

Scaling guidance:

— 0 Previous actions focus operators on the urgent need to act.

— 1 There are no distractions from this action; it is subject to close supervision and follow-up.

— 2

— 3 Operators are alerted to the need for possible action and are expecting it.

— 4 Another step in standard or procedure-based responses.

— 5 Action is not a surprise, but previous actions create some competition for operator attention.

— 6

— 7 This is one of many concurrent actions and could possibly be overlooked. Operator is taking recovery actions from one or two previous problems.

— 8 Operators are busy with other work or operators are in normal shift operations, and this is an unexpected, unusual transient.

— 9 Previous operator problems create an unusual situation.

— 10 The need to accomplish this action is unexpected and inconsistent with previous actions.

Consensus notes:

Examples of action groupings might be:

- Actions for which training and plant indications dominate, such as manual control of plant parameters.
- Actions for which time and preceding actions are most important, such as memorized immediate actions in response to a scram.
- Recovery actions for which the training and experience, the complexity of the action, and time available are important.

Grouping actions eliminates the need to quantify on the same scale actions that do not present the operators with the same types of problems. It permits the human action analyst to focus on those factors that most influence the error rate of the group of actions.

Calibration tasks are chosen for each group of actions. Calibration tasks have "known" or "accepted" values of HER and are influenced by PSFs with the same relative weights as the group of actions. The selection should include, if possible, one task that has a high likelihood of failure and one that has a low likelihood of failure. Calibration tasks are rated in the same way as the actions, and they form the basis for translating the FLI into human error rates. Calibration tasks are selected from human error rates determined from PRAs of other nuclear power plants using the results of human reliability experiments.

Additional calibration points can be obtained from best and worst case estimates of the influence of the PSFs on the group of actions being quantified. This technique involves estimating the likelihood of failure of a hypothetical action in which the group's PSFs combine to assist the operator (FLI = 0) or hinder the operator (FLI = 10) to the maximum extent possible. The result of this process is an estimate or the range of human error rates over which the group of actions may vary.

The failure likelihood index and HER of the actions are determined using a Lotus 1-2-3 spreadsheet that implements Equation (4). An example is given in Table 3. The failure likelihood index is calculated by multiplying the weight of each PSF by the rating of its contribution to the failure of the action and adding the products. The program obtains the constants for Equation (4) from a least squares fit of the calibration tasks and calculates the HERs for each group of actions using those constants.

The uncertainties of the HERs can be estimated from the uncertainties associated with the calibration tasks and the spread of HERs among several assessment teams. The result can be expressed in terms of the 5th, 50th, and 95th percentiles to represent the distribution of human error rates.

As a final check of overall consistency, the HERs of actions in each group should be compared with those of other groups. A judgment can then be made about whether differences in HERs are warranted by the differences in the scenarios and PSF ratings.

Example

The Lotus spreadsheets for a group of actions that primarily involve action to manually control reactor parameters during a transient are given in Tables 3 and 4. Table 3 illustrates the calculation of the human error rates.

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Table 3. Example of the Spreadsheet to Quantify Human Error Rates Using a Failure Likelihood Index

PERFORMANCE-SHAPING FACTORS

	PLANT	ACTIONS	COMPLEXITY	PROCEDURES	TRAINING	TIME	STRESS	OTHER	FLI	HER	LOG(HER)
PSF Weights	0.3	0.1	0.1	0.15	0.2	0.1	0.05				
OPERATOR ACTIONS											
MAX HER	10	10	10	10	10	10	10		10.00	7.5E-01	-0.125
HEROF2	8	5	6	6	2	6	2		5.50	3.5E-02	-1.457
HERLI2	3	3	2	5	9	3	7		4.60	1.9E-02	-1.723
HEROL1	8	5	6	6	3	4	3		5.55	3.6E-02	-1.442
HEROF1	6	3	3	5	2	6	4		4.35	1.6E-02	-1.797
HEROL3	8	3	8	7	6	8	7		6.90	9.1E-02	-1.042
MIN HER	0	0	0	0	0	0	0		0.00	8.2E-04	-3.085
CAL 1	2	4	3	4	3	5	1		3.05	6.0E-03	-2.222
CAL 2	8	5	7	5	7	5	7		6.60	5.0E-02	-1.301
BEST CASE									0.00	1.0E-03	-3.000
WORST CASE									10.00	1.0E+00	-0.000

Regression Output:

Constant	-3.08525
Std Err of Y Est	0.162922
R Squared	0.989363
No. of Observations	4
Degrees of Freedom	2
X Coefficient(s)	0.2960667
Std Err of Coef.	0.0217072

Table 4. Example of the Spreadsheet to Quantify the Relative Contribution of Performance-Shaping Factors to Likelihood of Failure

PERFORMANCE-SHAPING FACTORS

	PLANT	ACTIONS	COMPLEXITY	PROCEDURES	TRAINING	TIME	STRESS	OTHER	TOTAL FLI
PSF Weights	0.3	0.1	0.1	0.15	0.2	0.1	0.05	0	
OPERATOR ACTIONS									
MAX HER	3.0	1.0	1.0	1.5	2.0	1.0	0.5	0.0	10.0
HEROF2	2.4	0.5	0.6	0.9	0.4	0.6	0.1	0.0	5.5
HERLI2	0.9	0.3	0.2	0.8	1.8	0.3	0.4	0.0	4.6
HEROL1	2.4	0.5	0.6	0.9	0.6	0.4	0.2	0.0	5.6
HEROF1	1.8	0.3	0.3	0.8	0.4	0.6	0.2	0.0	4.4
HEROL3	2.4	0.3	0.8	1.1	1.2	0.8	0.4	0.0	6.9
MIN HER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Note: Entries are the product of the PSF weight and the PSF rating.

The user enters the weights of the PSFs directly into the indicated row. The PSF ratings of each action and calibration task are entered in the appropriate column. The accepted values of HER for the calibration tasks are entered in the column marked HER. Once this is completed, the calibration constants can be calculated with the least squares linear regression package available through the DATA command of Lotus 1-2-3. Once this has been accomplished, the HERs for the actions are automatically calculated and converted to standard scientific format by the right side of Equation (4) and the antilog formula in the columns labeled LOG(HER) and HER, respectively. Best case and worst case HERs are also calculated to provide the user with information regarding the range of HERs that result from the calibration.

Table 4 illustrates the use of the individual products, $w_i r_i$, to determine the dominant contributors to the human error rate. For example, plant interface and indications of condition is the largest contributor to operator error for all but one of the actions addressed by this group. This is a result of the relatively large weight given to obtaining feedback from plant indications required for manual control. Risk management now involves determining the specific reasons for high ratings and obtaining expert opinions on the improvement in the rating that could result from specific modifications.

Conclusions

The application methodology has the following advantages:

- It provides an organized method of eliciting the estimates of expert judges who are most familiar with the problems of accomplishing the actions.
- It provides a mechanism by which human error rates can be estimated within the context of the scenarios in which they will be performed.
- The step-by-step documentation of the consensus process makes the estimates scrutable and provides feedback for improving operator training and procedures.
- The set of forms and instructions to explain and implement the procedure enables its consistent application on a long-term basis and provides the flexibility to update and add actions as additional insight into operator actions is gained.

In other words, the structured application of SLIM presented in this paper can both qualitatively and quantitatively represent the problems the operators face in the context of the scenario in which they must function.

References

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Responses to Questions Q1 Through Q4 from Sandia National Laboratory Regarding the STPEGS PSA

Q1: **One of the screening criteria employed was that if only one of three safety trains was in a fire area, then this area was screened from further analysis. However, at Peach Bottom the two most dominant fire areas had only one of three safety trains. Each of these areas was two orders of magnitude higher than the dominant fire scenario at STP. In light of the Peach Bottom results, please list which areas were screened by this step and list what safety systems or their associated cabling are present.**

Response:

In accordance with Section 8 (Spatial Interactions Analysis) of the South Texas Project Electric Generating Station (STPEGS) Probabilistic Safety Assessment (PSA), Subsection 8.5.3 (Scenario Impact Evaluation) the only areas screened from any quantitative review are areas in which events do not effect any system and do not cause any initiating event in the PSA. The following discussion provides additional clarification of the Spatial Interactions Analysis which was performed.

The STPEGS PSA utilizes a spatial interactions screening analysis as the basis for the fire analysis performed in the PSA. The Spatial Interactions Analysis is described in Section 8 of the PSA. This spatial interactions analysis (SIA) identifies locations in the plant which correspond with the fire zones identified in the STPEGS Fire Hazard Analysis Report (FHAR). Each zone is associated with a fire frequency and a specific inventory including equipment, components, control cable, power cable, other hazard sources, and mitigative features. These areas are then considered as potential fire locations which define scenarios requiring evaluation. These scenarios are summarized in Appendix D, Table D-6, in volumes 6, 7 and 8 of the PSA.

In order to perform the evaluation, each scenario is assigned to one or more of four classes (Class 0, 1, 2 or 3), and then further identified as meeting one or more of ten guidelines which specifies the basis for initial screening. These classes and criteria are defined in Section 8, pp. 8.5-3&4 of the PSA. The class and applicable guidelines for each scenario (Items 10 & 11) are identified in Table D-6. It is also indicated in this table, based on the application of the guidelines, whether further quantitative screening (i.e., beyond the guidelines) is to be performed (Item 9).

Class 1, 2 or 3 scenarios were subjected to initial quantitative screening per the applicable guidelines. Class 2 includes all scenarios which affect one or more trains of a single system only (for those systems which are modelled in the PSA). Only Class 0 scenarios ("scenario does not affect any system and does not cause any initiating event in the plant model") are ruled out from further consideration (per guideline 1, "if a scenario is in Class 0, its further study is not warranted for purposes of risk assessment.")

Supplemental Comments on Q1:

Comparison to the Peach Bottom plant is inappropriate. The Peach Bottom units are BWRs which were constructed in the late sixties and early seventies and went into commercial operation in 1973 and 1974. The South Texas Project units are state-of-the-art PWRs completed in 1988 and 1989 having a combination of redundancy and physical separation which makes direct comparison to other plants inappropriate.

In the case of the STPEGS three-independent-train safety system design, a fire at STPEGS which affects one train and does not cause a plant trip would put the plant into a state which could be compared to recently licensed PWRs which have two trains and which are in normal operation. A fire at STPEGS which disables a single train and which causes a plant trip could be compared to those same PWRs after a turbine trip. Since a fire initiating event frequency is approximately three orders of magnitude lower than a turbine trip, single-train fire scenarios are not an issue for STPEGS. In any case, these events are compared to the frequency of a similar system state from random failures, and if significant (i.e., more than one or two percent) they may be added to the system unavailability frequency. A review of the plant level results (i.e., sequences) provides confidence that this screening is acceptable. To analyze each single train fire scenario in detail would result in a high level of effort without commensurate value being added to the analyses.

Q2: The most dominant scenario was in the control room. However, the methodology employed in the quantification varies substantially from past PL&G fire PRAs and also is at variance with testing results from large scale enclosure tests. In past PL&G fire PRAs, the control room has been assumed to be abandoned and control of the plant is taken from the remote shutdown panel. Sandia sponsored large scale enclosure tests have shown that cabinet fires generate such intense smoke that within 6-8 minutes control of the plant from the control room would be virtually impossible. These tests were conducted with control room ventilation rates of up to ten room changes per hour. Therefore, the most likely scenario would be smoke-forced abandonment of control room and subsequent control of the plant from the remote shutdown panel. If the remote shutdown panel is truly independent of the control room, then it makes no difference whatsoever where the fire originated because all initial potential damage to safety controls would be bypassed. Please explain why STP is either at variance in control room design from past PL&G PRAs or what other factors led the analysts to modify their previous methodology. Using the past methodology for control room analysis would have the effect of increasing core damage frequency estimates by a factor of approximately fifty.

Response:

Several factors have influenced the approach taken in the STPEGS PSA to the control room fire analysis. Factors which influenced this approach include a more detailed focus on the modelling of external events such as fires in the control room, an expanded data base for control room fire events such as that utilized in the fire analysis performed on the Surry plant for NUREG-1150, and the impact of the STPEGS independent three-train design on the consequences of fires.

Past PRAs have focused more on the internally-initiated event analysis due to the greater interdependency of systems design in older plants than the independent three-train design of STPEGS. As a consequence, the approach taken in previous PL&G fire PRAs has been more conservative in assuming abandonment of the control room in the case of a fire while concluding that even in such case, fire-induced core damage is a relatively small contributor (on the order of 10% plus or minus).

The STPEGS PSA fire analysis assumes a mean initiating event frequency of 4.9E-3 for control room fires. This frequency is taken from a paper by M. Kazarians and G. Apostolakis ("Modeling Rare Events: The Frequencies of Fires in Nuclear Power Plants," June 1982). This control room fire frequency is based on a single event which occurred during shutdown at Three Mile Island in 1979. The fire analysis completed for NUREG-1150 for the Surry

Power Station uses an initiating event frequency of 1.8E-3 (NUREG/CR-4550, "NUREG-1150 External Event Risk Analyses: Surry Power Station," September 1989, Table 5.5), a factor of approximately 3 lower than that used in the STPEGS PSA. This control room fire frequency is based on four events between 1978 and early 1983, including the Three Mile Island event (NUREG-4550, Appendix E, p. E-9). None of the four control room fires in the data base lead to the abandonment of the control room. NUREG-4550 assumes that 1 of 10 control room fires leads to abandonment of the control room (see Section 5.10.4 of NUREG-4550).

The STPEGS control room design is such that a fire on a control panel would be quickly detected by smoke detectors placed near the intake to the CR HVAC system inside the enclosed control panel housing. Separation is provided between panels and to a great extent between controls on the same panel. The fire would be extinguished quickly because of the detection and HVAC design and because the control room is continuously manned. NUREG-4550 also takes credit for a factor of 10 reduction in control room fire frequency because of continuous occupation (Section 5.10.4 of NUREG-4550). STPEGS has not taken this credit.

At STP, transfer of control to the auxiliary shutdown panel (ASP) provides control of safe shutdown equipment independent of the control room. A fire in the control room would disable equipment controls which would be restored by transfer to the ASP. The assumption in the STPEGS fire analysis does not take credit for transfer to the ASP since the equipment controls disabled by the control room fire represent the more limiting condition in terms of equipment available for plant shutdown.

Supplemental Comments on Q2:

The point made by the SNL reviewer that smoke from a fire in the control room is an important factor which may limit actions taken by an operator in the control room is a good one. It is also true that the abandonment of the control room is not explicitly modelled in the fire analysis. However, the analysis which is performed allows for operator actions in such a general and conservative way that plant control from the ASP or a local control panel would be an implicit alternative.

For example, Scenarios 2 through 6 (see pp. 9.4-6 through 9.4-10) consider various fires affecting loss of Component Cooling Water (CCW) and/or Essential Cooling Water (ECW). In each case, in order to restore cooling water to the Reactor Coolant Pump (RCP) seals, the use of the ASP was considered to restore the CCW/ECW function (in these sections, the term "hot shutdown panels" was used to refer to the ASP). The unlikelihood of restoration of CCW/ECW in these cases was 1.4E-2. This function could also be restored from a local control panel.

The SNL reviewer observes that "if the remote shutdown panel is truly independent of the control room, then it makes no difference whatsoever where the fire originated because all initial potential damage to safety controls would be bypassed". This cannot be the case even if the remote shutdown panel is independent, as is STPEGS's, since the location of the fire would influence the precise impact on the plant, timing of the scenario and time dependent indications to the operator.

For STPEGS, the ASP is located within the same building on a lower level which could be reached in a timely manner. Procedures provide for shift of control to the ASP in the event the control room becomes uninhabitable. Operator training and demonstrations provide confidence that the operators will effectively and efficiently take control from the ASP in order to shut the plant down. Cold-shutdown can be achieved from the ASP.

Of the 23 fire scenarios considered for the control room, other than the 5 referred to above, all assume failure of unspecified recovery actions by the operators with a likelihood of 0.2. This value is considered very conservative (i.e., high) as evidenced by the value of 1.4E-2 for the 5 discussed above for action taken from the ASP. The unspecified actions could include failure to take additional action in the control room and failure to take control of the plant from the ASP. If this were the case, and no additional recovery actions were taken from either the control room or the ASP, which is highly unlikely, then all of the fire results listed in Table 9.4-3 would be considered as the final fire results. In this case, the total fire induced core damage frequency would be approximately 2.5E-6, or about 1.5% of the CDF.

Q3: The dominant fire scenario frequency was approximately 1.0E-7 per year. One screening criteria to eliminate fire areas was at a frequency of 2.0E-7 per year. I feel it is inappropriate to set screening levels above the ultimate total fire-induced core damage frequency. Please list which fire areas were eliminated by this consideration and what safety equipment they contain.

Response: Fire areas are not screened by application of this criteria.

Supplemental Comments on Q3:

The comparison of the screening value of 2.0E-7 to 1.0E-7 as the "ultimate total fire-induced core damage frequency" is incorrect. The total core damage frequency resulting from fire-initiated events is approximately 5.06E-7, which is 0.3% of the total STPEGS estimated core damage frequency (CDF) of 1.67E-4. Thus, the screening criteria of 2.0E-7 is below the total core damage frequency due to fires. This total for fires is due to two fire scenarios, including 4 sequences, all of which occur in the control room. Fires in other locations were determined to be insignificant contributors to CDF.

The value of 0.3% as the percentage contribution of fires to STPEGS CDF was previously provided to SNL at the meetings held in STPEGS offices on November 28-30, 1989. This was in response to a question regarding the core damage frequency resulting from fires at the meeting with NRC and SNL personnel in Albuquerque on August 8, 1989. In addition, HL&P provided information regarding the dominant sequence at STPEGS due to a fire.

One correction should be noted to the information provided to the NRC and SNL at the November meeting (these meeting minutes have not been issued by the NRC at this time, so no reference is provided). The dominant fire sequence due to fires is approximately 1.9E-7 per year or approximately 0.1% of total CDF as previously indicated. However, the dominant sequence is as shown in Table 1. Table 1 also includes the sequence previously provided which is actually the third fire sequence in magnitude.

For additional discussion related to this question, see the section "Additional Comments" below.

Q4: Another screening criteria was to eliminate fire areas of 10% of internal events frequency for a similar end state. Once again, this has the potential for elimination of fire areas with contributions to core damage greater than the ultimate dominant scenario. Please list what fire areas were eliminated in this step and what safety equipment they contain.

<u>Response:</u> Fire areas are not screened by application of this criteria.

Additional Comments:

In regards to the methodology and reporting employed in the fire analysis:

- o Insufficient documentation exists in the report to do an adequate review of results of methodology employed.
- o Screening criteria are non-conservative and have the potential to dismiss relatively dominant (when compared to total fire-induced core damage frequency) fire areas.
- o The control room analysis does not appear to have used past PRA and fire testing insights and, therefore, may have substantially underestimated core damage frequency.

Response:

o <u>Insufficient Documentation</u>

HL&P has submitted documentation to support the review of the PSA in accordance with the guidance given in GL 88-20. It is true that most of the actual calculations performed to establish the contribution to core damage are not reproduced in the South Texas Project Electric Generating Station (STPEGS) Probabilistic Safety Assessment (PSA). The PSA as it currently stands is very voluminous (27 volumes), and it was never the intent to include the calculation details. The methodology is described in the Sections 8 and 9 as discussed below. The actual calculations, consisting of numerous volumes and computer runs, were shown and identified to SNL personnel and were available for review by SNL personnel during the plant visit on November 28-30. At that time SNL personnel indicated that it was not necessary to review this documentation. HL&P believes that the documentation in the PSA provides the information required to answer the questions regarding methodology and to provide the details which have been addressed to the HL&P to date.

The documentation of the fire analysis and the results of the methodology employed is extensively documented in the STPEGS PSA. Table D-6 in volumes 6, 7 & 8 of the PSA catalogs and summarizes, among other events considered, all fire scenarios considered in the fire analysis. Each scenario lists the location, initiating event frequency, potentially affected equipment and components, additional factors affecting propagation, classes and categories which specifies the basis for screening, and the result of the initial quantitative screening process. The methodology utilized for the fire screening analysis is completely stated in Sections 8 (Spatial Interactions Analysis) and 9 (Internal Fires Analysis) with detailed examples of each which are in fact the dominant scenarios.

If after review of this information you determine that the actual calculations must be reviewed, HL&P requests that you return to the STP site to review the material.

- Screening Criteria are Non-conservative

HL&P considers that the screening criteria used are conservative and that the use of these criteria will identify any significant fire sequences which are similar in magnitude to the (already small) total fire-induced core damage frequency. Based on the four questions provided in the letter which conveyed these general comments (i.e., Sandia National Laboratory to Nuclear Regulatory Commission dated January 3, 1990), the following discussion assumes that this concern relates directly to those questions.

With regard to Q1, the only fire areas screened without any quantitative evaluation are addressed in Section 8 and are areas which do not effect any system and do not cause any initiating event in the PSA (i.e., Class 0 scenarios. See p. 8.5-3). All other fire areas are quantitatively evaluated. Tables 8.6-1 through 8.6-6 (pp. 8.6-3 through 8.6-24 inclusively) summarize the scenarios cataloged in Table D-6 for all types of events evaluated using the spatial interaction approach, including fires. Table 8.6-7 summarizes the results of the initial quantitative evaluation using the quantitative criteria stated in Section 8 (p.8.5-4 and p.8.5.-5). Application of the criteria to Tables 8.6-1 through 8.6-6 to produce Table 8.6-7 is straight forward. (Note: There are a few omissions from Table 8.6-7 not involving fire scenarios which were evaluated separately and found to be unimportant.) Each of these tables state the general impact of the event on the plant. Reference to Table D-6 in volumes 6, 7 & 8 provide the specific equipment effected. The fire scenarios included in Table 8.6-7 are then evaluated in Section 9.

The analyses in Section 9 of the PSA apply to specific equipment states which result from event trees developed and quantified as described in this section for each fire scenario. The use of screening criteria in this section apply to specific individual sequences resulting from the event tree quantification. Fire areas are not screened in this section; individual sequences representing specific equipment failure states are developed, quantified and evaluated. With regard to Question 3, the screening criteria referred to is used in Section 9.3.3 ("Step 3 - Second Level of Screening", pp. 9.3-4 and 9.3-5) and applies to sequences, not to fire areas. With regard to Question 4, the screening criteria referred to is used in Section 9.3.2 ("Step 2 - Event Tree Quantification and First Level of Screening", pp. 9.3-2 through 9.3-4) and applies to sequences, not to fire areas. The object of the screening by the application of these criteria is a specific sequence or equipment state, not a fire area. The application of the screening criteria is considered acceptable since, in each case, they are applied to specific sequences, not fire areas, and additional equipment failures and/or failure of operator actions must occur before core damage results. For example, with regard to Question 3, a screening criteria of 2.0E-7 as applied to a specific sequence which by itself does not lead to core damage is reasonable, even though the dominant fire sequence frequency is approximately 1.9E-7. Fires only contribute approximately 0.3% of core damage frequency and the sequences being screened by this criteria are less than approximately 0.1% of CDF and do not lead by themselves to core damage.

- Control Room Analysis Does Not Use Past PRA and Fire Testing Insights

The STPEGS fire analysis does use past PRA and fire testing insights. The response to Question 2 addresses this concern as it applies to the STPEGS PSA.

A PRA utilizes plant experience to the extent it is available to estimate the likelihood of events. The data for fires in control rooms, although sparse, does not support the contention that any fire in the control room leads to abandonment. To the contrary, of the four minor fire events in the data base for control rooms, including one in 1979 at Three Mile Island when the plant was in a shut-down condition, all occurred in 1983 or earlier and no fire led to abandonment of the control room. The requirements of 10 CFR 50 Appendix R, "Fire Protection", went into effect in February 1981 and the implementation of its requirements since that time would be expected to favorably influence the unlikelihood of fires in nuclear power facilities. The STPEGS control room fire analysis assumes an initiating event frequency of 4.9E-3 based on this early experience rather than the less-conservative frequency of 1.8E-3 used in the NUREG-1150 control room fire analysis for the Surry plant.

SNL has conducted fire experiments which indicate that cabinet fires generate such intense smoke that within 6-8 minutes control of the plant from the control room would be virtually impossible. While this may occur, experience indicates that such fires are rare, and in fact have not happened. Even in the recent fire at the Vandellos plant in Spain where intense smoke entered the control room from a fire outside the control room (an oil fire lasting several hours in the turbine building in which the control room is located), operators were not forced to abandon the control room. In fact, the NUREG-1150 external events analysis for the Surry plant which was performed in part by SNL personnel (NUREG-4550, "NUREG-1150 External Event Risk Analyses: Surry Power Station", Section 10.5.4), assumed that only 1 of 10 control room fires lead to the abandonment of the control room.

Concern has been expressed that the STPEGS control room fire analysis did not assume the control room was abandoned in the event of any fire. Abandonment of the STPEGS control room would result in transfer of control to the auxiliary shutdown panel (ASP). A fire in the control room would disable equipment controls which would be restored by transfer to the ASP. All three trains of safety systems at STPEGS are controlled from the ASP, not just a single pathway as specified in Appendix R. The assumption in the STPEGS fire analysis does not take credit for transfer to the ASP since the equipment controls disabled by the control room fire represent the more limiting condition in terms of equipment available for plant shutdown and therefore is conservative.

Table 1
Summary of Sequences Initiated By Fire

Sequence	Frequency	Description
1	1.913E-7	FR18*AFR*(Success Terms) FR18 = 2.100E-6 (see PSA p.9.4-18). Control Room fire, Scenario 18, initiating event. Fire disables EAB/CR HVAC controls. AFR = 1.096E-1 (see PSA p.5.5-77). AFW train D fails. Success Terms = 8.312E-1 (see Note 1).
2	1.445E-7	FR18*PDH*(Success Terms) FR18 = 2.100E-6 (see PSA p.9.4-18). Control Room fire, Scenario 18, initiating event. Fire disables EAB/CR HVAC controls. PDH = 9.297E-2 (see PSA p.5.5-78). Failure of positive displacement pump given no charging and all support available. Success Terms = 7.401E-1 (see Note 1).
3 (Note 2)	9.949E-8	FR18*ORM*(1-CPC) FR18 = 2.100E-6 (see PSA p.9.4-18). Control Room fire, Scenario 18, initiating event. Fire disables EAB/CR HVAC controls. ORM = 6.161E-2 (see PSA p.5.5-8). Operator fails to start a train of HVAC having no automatic start signal. CPC = 2.31E-1 (see PSA p.5.5-8). No support available (1-CPC means support is available).
4	5.058E-8	FR23*OBA*(Success Terms) FR23 = 1.600E-6 (see PSA pp.9.4-17,18). Control Room fire, Scenario 23, initiating event. Fire disables all four trains of AFW. OBA = 4.802E-2 (see PSA p. 5.5-79). Operators open 2/2 PORVs for bleed and feed. Success Terms = 6.583E-1 (see Note 1).

Note 1: The frequency for successful operation of the remaining systems is not shown, but is included in the total sequence frequency.

Note 2: Previously provided to NRC and SNL personnel as the "Top Ranking Fire Event".

ATTACHMENT 1 **Page 1**

RESPONSES TO STP PSA FIRE RISK QUESTIONS

REVIEW QUESTION 1

1. The staff observes that the combined reduction factors (a combination of assigned geometry factors and severity factors) documented in Table 9.3-8 seem to be lower than those documented in other PRAs. For example, the reduction factor used for 4.16KV switchgear rooms seem to be substantially lower than used in the Diablo Canyon PRA (1.0) and NUREG-1150 risk analyses. Based on a review of existing deterministic fire analyses (such as areas of cable location identification, postulated cable (and other transient combustibles) burn and/or heat load calculations, associated time dependent suppression probability distributions) provide the basis for the appropriateness of the use of these reduction factors for the critical fire zones, including the 4.16KV switchgear room. If no supporting analyses exist at this time, the licensee should provide detailed rationale (zone-specific qualitative arguments) regarding the applicability of the reduction factors used for all critical fire zones. Sensitivity analyses of the assignment of higher combined reduction factors to each fire zone to develop perspectives of the impact on overall core damage frequency could be used to support the qualitative arguments.

Response: It is important to understand that fire frequency reduction factors were applied only to the 40 fire scenarios listed in STP PSA Table 9.3-1. All other fire scenarios initiated from the 190 zones presented in Table 8.5-2 were determined to be quantitatively insignificant contributors to core damage at STP without the application of fire zone geometry or severity factors. Thus, evaluations for the vast majority of possible fire scenarios in the STP PSA were based only on the conservative unmodified total annual fire frequencies listed in the third column of Table 8.5-2.

The reduction factors that are documented in STP PSA Table 9.3-8 were based primarily on the engineering judgment and experience of the PLG fire risk analysts. They are supported by the database for fire event occurrences that was available when the STP PSA fire analysis was performed in 1987, and they were derived from more detailed deterministic fire growth and damage models in previous fire risk analyses that had been performed by PLG.

In lieu of providing detailed reduction factor derivations for each fire scenario in Table 9.3-1, this response presents the results from sensitivity studies that demonstrate the quantitative unimportance of these fires without considering the effects from global reduction factors in each zone. This approach was adopted as a more effective method for presenting the STP PSA fire scenarios in their proper quantitative perspective than simply defending the specific numerical reduction factors that were applied in each fire zone. These sensitivity studies followed the original fire screening analysis process with four changes.

(1) All global fire frequency reduction factors were removed from the analysis of each fire scenario. The first level of screening, event tree quantification, and the second level of screening were all based on the unmodified total fire initiating event frequency for each zone listed in the third column of Table 8.5-2. (For example, the total reduction factor for fire scenario Z052-FS-01 from Table 9.3-8 was set equal to 1.0.)

(2) The 10% numerical screening criterion for comparison of each fire scenario end state with its corresponding internal event failure impacts was replaced by an even more conservative 1% criterion. Thus, in the first level of screening, an end state was eliminated from further consideration only if its fire-induced frequency of equipment damage was less than 1% of the frequency of the same damage caused by internal initiating events and system failures.

(3) The sensitivity studies were based on the analyses and results documented in the STP PSA final report. The original fire scenario screening analyses were performed at a stage in the study when preliminary quantitative results were available from the analyses of all important internal initiating events and system failures. Changes to the models for testing and maintenance unavailability for some systems near the end of the study and completion of the event tree analyses for all internal initiating events resulted in some quantitative changes to the original screening calculations. The sensitivity studies incorporated these changes so that all numerical calculations can be derived directly from information documented in the STP PSA final study report. The most notable of these changes was the replacement of the numerical criterion for core damage frequency used in the second and third levels of screening. The original analyses used a value of 2.0E-07 per year, which was approximately one-tenth of one percent of the preliminary internal event core damage frequency. Since the final STP core damage frequency from internal events is approximately 1.7E-04 per year, this screening criterion was reduced to 1.7E-07. (Refer to the response to Question 5 for more information on this criterion.)

(4) Specialized reduction factors that account for the fire zone geometry and fire severity were applied only to selected fire scenario end states in the third level of screening. These reduction factors were developed only after the analyses had identified specific sets of critical component failure modes and cable faults that dominated a fire scenario end state's contribution to core damage. The example for fire scenario Z004-FS-01 end state 11 in the response to Question 4 illustrates the derivation and application of one set of these reduction factors.

It should be noted that none of the reduction factors discussed in item (4) have been included in any of the sensitivity study results reported in this response to Question 1.

The details of these sensitivity studies are too voluminous to formally include in this response. However, the examples for fire scenario Z004-FS-01 in the response to Question 4 are derived from its sensitivity study, and they illustrate all important facets of the analysis process. All supporting calculations for the original fire screening analyses and these sensitivity studies, with appropriate explanatory annotations, are available for review at the HL&P offices.

The sensitivity studies showed that 29 of the 40 fire scenarios from Table 9.3-1 could be eliminated from further consideration without the application of any fire zone geometry or severity factors. Table 1-1 lists the end states that did not meet the revised screening criteria for each of the remaining 11 fire scenarios.

The example for fire scenario Z004-FS-01 in the response to Question 4 shows that application of justified and well-documented geometry and severity factors reduces the estimated core damage frequency in end state 11 from approximately 1.25E-06 per year to approximately 1.63E-07 per year. (The discussion for that analysis notes that even this result contains some conservatisms that could be reduced by a more thorough examination of all control cable functions, identification of specific tray routings for all critical cables, and consideration of the relative timing between fire-induced faults and independent component failures.) Thus, the total effective reduction factor for this end state is approximately 0.13; i.e., a factor of 7.7. Although it is not prudent to extrapolate from a zone-specific analysis to a general conclusion, if a similar reduction factor were to be achieved for each of the other end states in Table 1-1, only three would remain above the 1.7E-07 core damage frequency screening criterion: zone

Z016 end states 43 and 44, and zone Z122 end state 43. In fact, of the 21 end states in Table 1-1, 12 would fall below this screening criterion with a reduction factor of less than 3; 5 would fall below the criterion with a reduction factor in the range from 3 to 5; and 2 would fall below the criterion with a reduction factor in the range from 5 to 10.

The results in Table 1-1 confirm the original conclusion that fires in these zones are quantitatively unimportant contributors to the frequency of core damage at STP. The underlying sensitivity studies have assumed that <u>every</u> fire in each of these zones will damage <u>all</u> critical cables in that zone. Even without the application of any reduction factors to account for the fire zone geometry or the severity of fires necessary to damage a critical set of components, an upper bound estimate for the total core damage frequency from the fires in Table 1-1 is approximately 1.5E-05 per year. If this total were added to the core damage frequency from all other events analyzed in the STP PSA, the final mean core damage frequency would increase from approximately 1.7E-04 per year to approximately 1.8E-04 per year. It must be emphasized that this increase is the <u>maximum</u> possible effect from all these fires if absolutely <u>no credit</u> is taken for any geometry or severity reduction factors. Although the bases for these reduction factors are often challenged in open reviews of contemporary fire risk studies, all modern fire analyses acknowledge that some reasonable numerical credit must be assigned to account for the fact that not every fire in a particular zone will damage all the critical components and cables in that zone. The relatively insignificant damage experienced during the majority of actual fires in nuclear power plants and the extensive plant-specific fire mitigation features in the STP plant design clearly support this conclusion.

Table 1-1. Sensitivity Study Fire Scenarios That Do Not Meet Screening Criteria Before Application of Fire Zone Geometry and Severity Factors

Fire Zone	End State	Estimated Total Core Damage Frequency Without Geometry and Severity Factors	Fraction of STP Core Damage Frequency
Z004	11	1.25E-06	0.00735
	12	5.34E-07	0.00314
Z006	9	5.56E-07	0.00327
Z010	5	3.17E-07	0.00187
Z016	43	3.61E-06	0.02124
	44	1.55E-06	0.00912
Z026	17	4.94E-07	0.00291
	18	2.11E-07	0.00124
	19	2.11E-07	0.00124
	34	1.99E-07	0.00117
	36	8.31E-07	0.00489
	52	6.72E-07	0.00395
Z031	9	3.25E-07	0.00191
Z042	9	2.16E-07	0.00127
Z047	53	4.21E-07	0.00248
	59	1.81E-07	0.00107
	66	5.14E-07	0.00302
	72	2.20E-07	0.00129
Z122	43	2.02E-06	0.01188
Z139	4	2.47E-07	0.00145
Z142	74	2.26E-07	0.00133
TOTAL		1.48E-05	0.08709

RESPONSES TO STP PSA FIRE RISK QUESTIONS

REVIEW QUESTION 2

2. For control room fire scenario (Scenario 6), the licensee has assigned a severity factor in the range of 0.072 to 0.0015 to evaluate the propagation characteristics of the postulated cabinet (panel) fires. Experimental tests conducted at SNL have shown that a postulated panel fire could virtually damage the entire panel within a relatively short period of time (e.g., five minutes). Thus, the staff questions the licensee's assignment of the lower severity factor for the panel fires (relative to those used in the Diablo Canyon PRA and NUREG-1150 risk analyses). Therefore, the licensee should provide a detailed rational (qualitative arguments) regarding this assignment of the lower severity factors for the panel fires. These rationales should not be limited to panels located only in the control room.

Response: In assessing the appropriateness of the severity factors listed in STP PSA Table 9.4-2, a number of points are relevant.

(1) Although experiments do show that large fires in electrical panels (not including MCCs and high voltage switchgear) can be initiated*, most (if not all) of the electrical panel fires that have been actually observed in nuclear power plants have been small. The SNL tests provide an indication of the possibilities for fire propagation, but they were not conducted in a manner to support the derivation of the frequency vs. severity characteristics experienced in actual nuclear power plant fires. Examination of the fire occurrence database provides more useful insights into this necessary information. Table 2-1 lists 13 electrical panel and relay fires included in the PLG database (Reference 1). This database is an extension of the SNL fire database (Reference2). Based on the descriptive narratives included in the database, none of the 13 fires seems to have caused widespread damage. For two of the earlier events, Reference 4 estimates damage radii of 1 foot or less. A more recent review of the narratives for the events in Table 2-1 was also performed in support of this Response (Reference 5).

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*It should be noted that even in a controlled experimental situation, the initiation of a self-propagating cabinet fire is not necessarily a simple task. Reference 3 identifies a number of factors that can affect the likelihood of propagation. For example, in the experiments discussed in that reference, the wires had to be carefully preheated prior to ignition. If the wires were not preheated at all, or if they were preheated too much, ignition could be achieved, but the fire tended to self-extinguish.

In this review, it was possible to estimate damage radii for 8 of the events. (The narratives for the remaining 5 events do not provide enough information to allow such estimates.) The conclusions from this review are that none of the events had a damage radius greater than 1 foot and that most of the events were substantially smaller. Therefore, the results from this review of actual nuclear power plant panel fire data indicate that the curve shown in STP PSA Figure 9.4-1 may actually be somewhat pessimistic. Figure 9.4-1 was the basis used to develop the panel fire severity factors in Table 9.4-2.

(2) Fire suppression, although not explicitly modeled with a separate factor in this analysis, clearly cannot be ignored in the continuously manned control room. (It may be argued that, at least in the case of control room fires, the relatively quick detection and suppression of these fires has led to the lack of any large panel fires in the database.) As in the Diablo Canyon PRA (Reference 6), the severity factors used in the STP PSA fire analysis implicitly include the effects from suppression efforts on the likelihood of fire damage*. When this implicit model for detection and suppression is taken into account, the assessments reflected in the curve of STP PSA Figure 9.4-1 are reasonable; e.g., that 90% of all control room panel fires have effective damage radii less than 2.5 feet.

(3) The minimum effective fire damage radius needed to cause the damage modeled in STP PSA control room fire scenario 6 is approximately 3 to 4 feet. Based on the observations documented in the first two points above, it is evident that most actual panel fires (especially control room panel fires) are simply not large enough to cause damage over such large distances. Therefore, relatively small values for the effective severity factor for these panel fires are appropriate.

(4) The severity factors used in the STP PSA fire analysis are entirely consistent with those used in the Diablo Canyon PRA, since both studies used the same basis curve; i.e., STP PSA

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*It should be noted that the fire severity factor definition presented on STP PSA final report page 9.4-3 accounts for the damage <u>actually caused</u> by the fire, <u>not</u> the potential damage that could be caused if the fire were not suppressed. This definition deviates somewhat from that used in fire risk studies in which growth and suppression are modeled explicitly, and it may be a slight source of confusion.

Figure 9.4-1. Differences in the numerical results obtained in the two studies are due to differences in the damage scenario definitions and the control panel geometries. The effective severity factor of 1.0 used in the NUREG-1150 analysis of Surry control room fires (Reference 7) is considered to be too conservative for a realistic plant-specific risk analysis. For example, this factor implies that all fires in benchboard 1-1 (regardless of initial size, ignition source, fuel geometry, etc.) will cause damage to all critical components in that panel.

(5) Tables 2-2 and 2-3 show that the overall reduction factors used in the STP PSA, which account for the combined effects of control panel geometry and fire severity, are numerically comparable to those used in the Diablo Canyon PRA. In fact, the effective total reduction factor for the entire control room (i.e., the sum of the reduction factors for each of the scenarios, which quantifies the total fraction of control room fires that may cause significant damage) is considerably larger in the STP PSA (0.179) than the total reduction factor for the Diablo Canyon PRA (0.086) and that for the NUREG-1150 analysis of Surry (0.084). This may be due to plant-specific differences in the control panel geometries, but it is also almost certainly influenced by the greater level of detail in the STP PSA control room fire analyses. The STP PSA analyses evaluate 23 different control room fire scenarios, compared to 5 in the Diablo Canyon PRA and only 1 in the NUREG-1150 analysis of Surry.

In summary, the severity factor curve shown in STP PSA Figure 9.4-1 forms the basis for all the panel fire severity factors addressed in this question. The observations noted above indicate that this curve may, in fact, be a pessimistic representation of the effects from actual nuclear power plant panel fire experience, both inside and outside the control room. The STP PSA curve is identical to the curve used in the Diablo Canyon PRA. The relatively small values for the severity factors listed in STP PSA Table 9.4-2 are due to the following facts:

(a) Key components on the STP control panels are generally separated by a substantial distance. Thus, some period of time is required for a fire to propagate before it affects a critical set of equipment.

(b) The effects from fire detection and suppression are already included implicitly in the STP PSA fire severity curve.

The numerical values of the STP PSA reduction factors do not necessarily contradict the SNL experimental results, since the experiments clearly demonstrate that self-propagating panel fires are not easy to start under arbitrary conditions. Finally, the combined reduction factors for individual scenarios, which include geometry and severity considerations, are consistent with those used in the Diablo Canyon PRA. The total reduction factor for the STP control room is larger (i.e., more conservative) than that for Diablo Canyon or Surry.

Table 2-1. Relay and Electrical Panel Fires in the PLG Database

ID	Location	Fire Size	Fire Duration	Class	Other References
156	Sprdg Rm	S	00:45	1B,1A	BWR-2 IX E p68 289*, 40** A-54***
166	Aux Bldg	M	00:12	1C,1A	BWR-2 IX E p75 327*, 41**
169	Aux Bldg	M		1C,1A	BWR-2 IX E p100 461*
188	Ctrl Bldg	S		1B,1A	B-4C***
225	Ctrl Room	M	<00:05	1B,1A	PWR-2 IX H p48 266*
271	Othr Bldg	M		1B,1A	
295		S		1B,1A	BWR-2 IX B p33 199*
318	Othr Bldg	M		1B,1A	
331	Ctrl Bldg	M		1B,1A	
336	Comp Room	M		1B,1A	
384	Rx Bldg	S		1B,1A	BWR-2 XIV B p154 632*
397	Ctrl Room	P		1B,1A	BWR-2 XIV B p91 395*
398	Ctrl Room	P		1B,1A	BWR-2 IX C p19 113*

NOTES:

1. Radius of fire 156 estimated to be 0.5 ft sphere (Reference 4).
2. Radius of fire 166 estimated to be 1 ft sphere (Reference 4).
3. The ID number in this table generally coincides with the Incident Number (INO) assigned in Reference 2.
4. The following qualitative guidelines apply to Fire Size:
   - L = Large: Affects multiple components, may require large-scale suppression efforts (e.g., offsite fire department, multiple hoses).
   - M = Medium: Single component damage, can be extinguished by onsite fire brigade, several hand-held extinguishers.
   - S = Small: Localized damage, can be extinguished by one person without assistance.
   - P = Precursor: Fire never propagates, likely to self-extinguish.
5. Fire Durations listed in hours:minutes.
6. Class column specifies Ignition Class, Fuel Class:
   Ignition Class:
   - 1A = In situ ignition source, normally present (e.g., hot surfaces)
   - 1B = In situ ignition source, component failure
   - 1C = In situ ignition source, human error
   - 2D = Transient ignition source, used in room
   - 2E = Transient ignition source, administrative violation

Table 2-1. (Part 2 of 2) Relay and Electrical Panel Fires in the PLG Database

Fuel Class:	1A = In situ fuel, anticipated (e.g., insulation)
	1B = In situ fuel, unanticipated (e.g., wrong material)
	2C = Transient fuel, used in room
	2D = Transient fuel, stored in room
7. Other References:	* = Reference 8.
	** = Reference 4.
	*** = Reference 9.

Table 2-2. Mean Reduction Factors Used in the STP Control Room Fire Analysis

Scenario	Panel	Size	Mean Reduction Factor	Damaged Equipment
1	1	L	0.0019	3 Trains ECCS
2	1	S	0.028	3 Trains CCW
3	2	S	0.028	3 Trains CCW
4	1	M	0.0053	3 Trains CCW, 1 Train ECW
5	2	M	0.0037	3 Trains CCW, 2 Trains ECW
6	1/2	L	0.0028	3 Trains CCW, 3 Trains ECW
7	3	M	0.0043	2 AC Buses
8	3	M	0.0043	2 AC Buses
9	3	L	0.0023	3 AC Buses
10	22/1	S	0.012	3 Trains AFW Ventilation
11	22/2	M	0.012	CCW and Charging Ventilation
12	22/2	M	0.0090	3 Trains ECH
13	22/2	S	NA	2 Trains ECW Ventilation
14	22/2	S	NA	2 Trains ECW Ventilation
15	22/2	M	0.0064	3 Trains ECW Ventilation
16	22/4	L	0.0091	2 Trains EAB HVAC, Control Room Envelope Supply/Exhaust, Outside Air Makeup
17	22/4	L	0.0091	2 Trains EAB HVAC, Control Room Envelope Supply/Exhaust, Outside Air Makeup
18	22/4	L	0.0037	3 Trains EAB HVAC, Control Room Envelope Supply/Exhaust, Outside Air Makeup
19	4	S	0.012	Small LOCA
20	6	M	0.0097	2 Trains S/G Control
21	6	M	0.0097	2 Trains S/G Control
22	6	L	0.0027	3 Trains S/G Control
23	6	L	0.0032	4 Trains S/G Control
TOTAL			0.1792	

NOTES:

1. 1/2 indicates that fire occurs at interface between panels 1 and 2.

2. Fire Sizes: S = Small
   M = Moderate
   L = Large

Table 2-2. (Part 2 of 2) Mean Reduction Factors Used in the STP Control Room Fire Analysis

3. NA for Scenarios 13 and 14 indicates that these scenarios were not analyzed separately. Their impacts are bounded by Scenario 15.

RESPONSES TO STP PSA FIRE RISK QUESTIONS

Table 2-3. Mean Reduction Factors Used in the Diablo Canyon PRA Control Room Fire Analysis (Reference 6)

Scenario	Panel	Size	Mean Reduction Factor	Damaged Equipment
1	VB-1	S	0.025	ASW, CCW
2	VB-2A	S	0.044	Small LOCA
3	VB-2B	M	0.0022	Small LOCA, Charging Pumps
4	VB-2/3	M	0.0055	Small LOCA, AFW
5	VB-4	M	0.0088	3 Trains AC Power
TOTAL			0.0855	

NOTES:

1. VB-2/3 indicates that fire occurs at interface between panels VB-2 and VB-3.

2. Fire Sizes: S = Small
M = Moderate
L = Large

References:

1. PLG, Inc., "Database for Probabilistic Risk Assessment of Light Water Nuclear Power Plants", PLG-0500, Volume 8, Fire Data, Revision 0, September 1990.

2. Wheelis, W.T., "User's Guide for a Personal-Computer-Based Nuclear Power Plant Fire Data Base", NUREG/CR-4586, SAND86-0300, Sandia National Laboatories, August 1986.

3. Spletzer, B.L., and F. Horine, "Description and Testing of an Apparatus for Electrically Initiating Fires Through Simulation of a Faulty Connection", NUREG/CR-4570, SAND86-0299, Sandia National Laboratories, June 1986.

4. Fleming, K.N., W.J. Houghton, and F.P. Scaletta, "A Methodology for Risk Assessment of Major Fires and its Application to an HTGR Plant", GA-A15402, General Atomic Co., July 1979.

5. Bromley, W., personal communication to N.O. Siu, August 29, 1990.

6. Pacific Gas and Electric Company, "Fianl Report of the Diablo Canyon Long Term Seismic Program", Chapter 6, Probabilistic Risk Analysis, July 1988; PLG, Inc., "Diablo Canyon Probabilistic Risk Assessment", PLG-0637, Appendix F.3, Diablo Canyon Fire Risk Assessment, Draft Report, August 1988.

7. "External Event Risk Analyses: Surry Power Station", NUREG/CR-4550, Volume 3, Revision 1, Part 3, prepared for the U.S. Nuclear Regulatory Commission by Sandia National Laboratories, September 1989.

8. S.M. Stoller Corp., "Nuclear Power Experience", updated monthly.

9. Dungan, K.W., and M.S. Lorenz, "Nuclear Power Plant Fire Loss Data", EPRI-NP-3179, prepared for the Electric Power Research Institute by Professional Loss Control, Inc., 1983.

RESPONSES TO STP PSA FIRE RISK QUESTIONS

REVIEW QUESTION 3

3. It is noted that the statements (refer to pages 8.5-15 and 9.4-1) regarding the dominant contributor (panel fires as opposed to transient combustible fires) to the initiating frequency of the control room fires (4.08E-3 per reactor-year) appear to be inconsistent. Current operating reactor experience shows that the panel fires dominate the initiating event frequency of the control room fires. Provide clarifications regarding the above inconsistent statements made in the PRA.

<u>Response:</u> The entry for control room fire zone Z034 in the "Occupancy" column of STP PSA Table 8.5-2 is somewhat misleading and should be revised or clarified. It is true that relatively small amounts of transient combustibles are present in all nuclear power plant control rooms. However, as noted in the question, experience has shown that cables are clearly a major, if not the dominant, source of fuel for the most important fires in this zone. The control room fire analysis presented in STP PSA Section 9.4 is consistent with this observation and with other PRA analyses because it focuses exclusively on panel fires. The final sentence in the first paragraph on page 9.4-1 may also lead to some confusion because it may be interpreted that the frequency of fires in a particular panel depends on the ratio of the panel area to the total <u>control room</u> area. The subsequent analysis (refer to Equation 9.4) correctly uses the ratio of the individual panel area to the total <u>panel</u> area in the control room. This calculation is also consistent with the assumption that panel fires dominate the control room fire frequency.

RESPONSES TO STP PSA FIRE RISK QUESTIONS

REVIEW QUESTION 4

4. For fire scenario Z004-FS-01, provide the derivation procedure used for the initiating fire frequency, discussions related to assignment of an additional random failure (0.01) in resulting sequences, and discussions related to other additional failures assumed prior to screening.

Response: The evaluation of fire scenario Z004-FS-01 will be used to illustrate all important facets of the STP PSA fire analysis methodology. Sections 8 and 9 of the STP PSA final report provide summary documentation to familiarize the reader with the basic elements of this methodology and background information for its numerical input data. Brief examples are provided to illustrate some of the more fundamental steps. However, as is the case with nearly all aspects of PRA, it was necessary in the formal study report to strike a balance among tutorial information, details of backup calculations, and sheer volume of the document. All supporting calculations for the screening analyses, with appropriate explanatory annotations, are available for review at the HL&P offices.

The evaluation methodology described in the following sections for Z004-FS-01 was applied to each of the 190 fire zones identified in STP PSA Table 8.5-2. The screening process was comprehensive and systematic. It was designed to efficiently identify fire scenarios that could measurably contribute to core damage. Each postulated fire scenario was run through the successively more detailed evaluation steps until there was full assurance that the fire need not be considered further as a quantitatively important contributor to core damage or plant risk. In most cases, fires were eliminated after a preliminary "high level" comparative numerical analysis. A small number of scenarios, identified in STP PSA Table 9.3-1, required more detailed analyses. Scenarios that were quantitatively significant enough to survive the full screening evaluation were formally propagated through the STP event tree models. Finally, the detailed backup documentation provides a fully traceable path that begins with the original scenario definitions from the spatial interactions analysis and ends with the final fire scenarios quantified in the PSA results.

It should be noted that the evaluation presented below for Z004-FS-01 deviates in one important way from the methodology described in STP PSA report Section 9.3. Preliminary review comments and questions have raised concerns about the derivation and application of "reduction factors" to modify the frequency of fires in each of the 40 scenarios listed in Table 9.3-1. The response to Question 1 above addresses this issue more completely. The evaluation of fire scenario Z004-FS-01 presented below has removed all general area-wide reduction factors from the analysis. Specialized factors that account for the fire zone geometry and the fire severity are applied only in the final step of the evaluation process for selected end states where the critical cables, locations, and fire-induced equipment failure modes are fully defined.

<u>Task 1.</u> Derivation of Fire Scenario Frequency

Fire frequencies were allocated to zones within the Mechanical and Electrical Auxiliary Building (MEAB) in a five-step procedure.

(1) Area factors were computed for each zone based on the percentage of building floor area occupied by the zone. This value is shown in the "Percent Area" column in Table 8.5-2. For Zone Z004, the area factor is 0.01408.

(2) Modification factors were assigned to reflect the zone occupancy and traffic characteristics. These modification factors were assigned using a limited set of rules reflecting the judgment of the analyst concerning the relative frequencies of fires for different zone characteristics. For example, areas containing only power cables and control cables were assigned a modification factor of 0.75; areas containing switchgear were assigned a modification factor of 1.875 (the highest possible value); areas containing only piping and with low traffic levels (people are in the room 25% of the time or less) were assigned a modification factor of 0.125 (the lowest possible value). The qualitative bases for these factors are documented in the "Traffic" and "Occupancy" columns in Table 8.5-2. It is acknowledged that the assignment of these modification factors depends to some extent on the individual fire analyst's judgment and experience. However, this process provides a reasonable and consistent method of numerically accounting for the general notion that the frequency of fires in a given zone is influenced by the zone's location and its contents, in addition to its size. For Zone Z004, the modification factor is 1.875.

(3) Zones were examined on an individual basis during plant walkdowns, and a number of the modification factors were adjusted to reflect special conditions in the room. In the case of Zone Z004, no such modifications were judged necessary.

(4) Normalized area-modification factor products were computed using the following formula.

$$F'_{a,m}(i) = \frac{F_a(i)F_m(i)}{\sum F_a(j)F_m(j)}$$

where

$F_a(i) =$ area factor for zone i developed in Step 1.

$F_m(i) =$ modification factor for zone i developed in Step 3.

and the summation is performed over all zones. The numerical value of the normalization factor in the denominator of this formula is approximately 0.9507. Thus, for Zone Z004, the normalized area factor-modification factor product is 0.02777. This value is shown in the "Percent of Total for Building Category" column in Table 8.5-2.

(5) The normalized area factor-modification factor products were used to allocate the building fire frequency according to the following formula.

$$\lambda_i = \lambda_{MEAB} F'_{a,m}{}^{(i)}$$

where

$\lambda_{MEAB} = 0.048$ per year

The final fire frequency for Zone Z004 is therefore 0.00133 fires per year.

<u>Task 2.</u> Identification of Component and System Impacts

Table D-6 in Appendix D of the STP PSA final report contains detailed inventories of all PRA-related equipment and cables located in each fire zone. This table is the product of the spatial interactions analysis described in report Section 8. Table 4-1 reproduces this information for Zone Z004.

Each component and cable in every fire zone was examined by the STP PSA principal investigator and plant modelling task leader to determine the impacts from postulated open circuits and short circuits that could be caused by a fire in the zone. In many cases, it was noted that a short circuit in a particular power or control cable could have a significantly different effect on equipment operation and plant response than would be caused by an open circuit in the same cable. Thus, this review provided the method for translating the fire zone inventory information into a set of possible physical and functional impacts that could be evaluated in the STP PSA systems and event tree models. Tables 4-2 through 4-4 present this information for Zone Z004.

Since Zone Z004 is the ESF Train A switchgear room, it is not surprising that fires in this zone could have a significant impact on the availability of Train A equipment. However, Tables 4-2 through 4-4 also note possible impacts on equipment in other ESF trains and non-ESF equipment that is important to the risk model. These impacts include open circuits that prevent PORV 655A from opening, short circuits that cause PORV 655A to open spuriously, short circuits that cause the reactor head vent valves to open, short circuits that isolate the normal charging flow path, short circuits that disable the positive displacement charging pump (PDP), and short circuits that isolate component cooling water (CCW) flow to reactor containment fan cooler (RCFC) Train C.

<u>Task 3.</u> Preliminary Screening Evaluation

The possible impacts from the fire scenario were next examined to determine a preliminary categorization of the fire event according to the four classes described in STP PSA report Section 8.5.3. This classification was based on the combined set of all identified impacts, assuming that every fire in the zone would cause the worst possible combination of open circuit and short circuit failures. Fire scenario Z004-FS-01 was determined to cause an initiating event (Class 1) and to affect equipment in more than one ESF train (Class 3). None of the possible impacts from any fire in this zone lead directly to core damage.

The frequency of the fire scenario was next compared with the corresponding frequency of the same set of combined impacts caused by an internal initiating event and random system failures. This "high level" comparison determined whether the fire scenario was already bounded numerically by internal event sequences that would lead to core damage at much higher frequencies than the worst possible combination of fire-induced failures. Table 4-5 documents combinations of internal initiating events and system failures that lead to the same impacts as fire scenario Z004-FS-01, with their corresponding point-estimate frequencies. Assuming that all fires in this zone cause the worst possible combination of equipment failures, the total frequency for fire scenario Z004-FS-01 is 1.33E-03 event per year. Comparison of this frequency with the estimates in Table 4-5 shows that the possible fire-induced failures are not numerically bounded by the corresponding combinations of internal events. Therefore, fire scenario Z004-FS-01 was retained for more detailed analysis.

It should be noted that no reduction factors were applied to the frequency of fires in any zone through this point in the evaluation process. All event classification and screening was performed based on the assumptions that the worst possible combination of equipment failures would be caused by every fire in the zone and that these failures would occur at the full frequency of all fires in the zone. It should also be noted that only 40 of the fire scenarios initiated from the 190 fire zones listed in Table 8.5-2 required further analysis beyond this point in the evaluation process. These 40 scenarios are listed in STP PSA report Table 9.3-1.

<u>Task 4.</u> Development of Fire Scenario Event Tree and Impact End States

Fire-induced short circuits in equipment power or control cables often cause responses that are much different from open circuits in the same cables. For example, in fire scenario Z004-FS-01, a sustained "hot" short may cause pressurizer PORV 655A to open spuriously and lead to a small LOCA event scenario. An open circuit may prevent the valve from opening for the bleed and feed mode of core cooling. In order to differentiate between the physical and functional impacts from these possible fire-induced failure modes, simplified event trees were constructed for each of the 40 fire scenarios listed in Table 9.3-1. These event trees also identified simple operator recovery actions that could mitigate the fire impacts through manual operation of components or use of alternate equipment not affected by the fire. Figure 4-1 shows the event tree for fire scenario Z004-FS-01.

To understand the logic of this event tree, consider the first two top events, PL and BF. Top Event PL fails if a sustained "hot" short circuit causes pressurizer PORV 655A to open spuriously and remain open. A fundamental assumption in these event trees was that no credit was taken for fire-induced failures that could mitigate the impacts from other fire-induced faults. Thus, it is assumed that an open circuit prevents PORV block valve MOV0001A from closing to isolate the resulting small LOCA. On the failure path from Top Event PL, the only other top events questioned are PD and FC. This logic accounts for the fact that normal charging flow is not sufficient to mitigate the effects from a stuck-open PORV and, therefore, the status of the charging system is insignificant to the progression of this event. Since RCFC Train

C provides a method for removing core decay heat during high pressure recirculation scenarios, its status is relevant during a small LOCA.

Success of Top Event PL occurs if there is no sustained "hot" short circuit that keeps PORV 655A open for an extended period of time. Under this condition, Top Event BF models the effects from an open circuit that prevents PORV 655A from opening. The STP PSA event model success criteria require both pressurizer PORVs to be opened for bleed and feed cooling. Therefore, failure of Top Event BF disables this alternate mode of core cooling if it is required following a loss of all steam generator heat removal. The remaining top events are questioned after both success and failure of Top Event BF, because the status of the charging system, the PDP, and RCFC Train C is relevant for possible event scenarios that may proceed from any plant transient.

It should now be recognized that the event tree evaluates the possible status of only a small subset of all the equipment that may be affected by the fire. The remaining equipment is collected in a set of "baseline" system failures. It is assumed that <u>every</u> fire in the zone disables <u>all</u> the equipment in this baseline set. Table 4-6 lists the baseline set of failures assigned to fire scenario Z004-FS-01. Combinations of the event tree top event successes and failures determine the physical and functional impacts from the corresponding fire-induced short circuits, open circuits, and operator actions. These impacts are collected in "end states" that characterize each path through the event tree. The event tree end state impacts are then added to the baseline system failures to fully specify the plant-level impact from each event tree path. Table 4-7 lists the combined baseline and event tree impacts for each end state defined in Figure 4-1.

The event tree is quantified using the fire scenario frequency as the initiating event frequency. (It is at this point in the evaluation process that the first "reduction factors" were applied during the original fire screening analysis. These reduction factors have been removed from this evaluation of fire scenario Z004-FS-01.) It sholuld be noted that the conditional frequency of fire-induced open circuits was assumed to be 1.0 for all event tree quantification runs. Thus, unless the fire causes a short circuit in a cable, the cable was assumed to experience an open circuit. In the event tree for fire scenario Z004-FS-01, the conditional frequency of a sustained "hot" short circuit that keeps the pressurizer PORV open until the core uncovers was assigned a value of 0.0125. This means that Top Event PL fails during 1.25% of the fires in zone Z004. The assumption of a conditionally-guaranteed open circuit also means that Top Event BF fails during the remaining 98.75% of the fires in zone Z004. These assumptions preclude the combined success of Top Events PL and BF, and they eliminate any frequency from appearing in the first 60 sequences from Figure 4-1.

Task 5. First Level of Scenario Screening Evaluation

The first level of quantitative screening compared the frequency of each event tree end state with the corresponding frequency of the same set of combined impacts caused by an internal initiating event and random system failures. This process is similar to the preliminary screening described in Task 3. However, it is more focused, because specific combinations of fire impacts and their relative contributions to the total fire scenario frequency have been clearly delineated by the event tree analysis.

Quantification of the event tree for fire scenario Z004-FS-01 resulted in the total fire frequency being allocated among 6 of the 20 possible impact end states. The noted assumptions about conditionally-guaranteed open circuits eliminated the possibility for the fire to cause any of the impacts in the remaining 14 end states; e.g., end states that have both Top Events PL and BF successful. Table 4-8 summarizes the combinations of internal events that are equivalent to each of these 6 fire-induced impacts. The table also includes a point-estimate quantification of each set of internal events that is derived from the initiating event data, systems analyses, and human reliability analysis documented in the STP PSA final report.

Table 4-9 provides a summary of the quantitative results and the bases for screening each end state for fire scenario Z004-FS-01. The first column is the total fire-caused frequency of each end state from quantification of the fire scenario event tree. (It should be noted that all fire frequency reduction factors have been removed from this analysis. The sum of the end state frequencies in Column 1 is equal to the total fire frequency for zone Z004; i.e., 1.33E-03 fires per year.) The second column in Table 4-9 lists the equivalent internal event frequency from Table 4-8. The first level of screening compared the values in Columns 1 and 2. If the frequency of the fire-caused impact was less than 1% of the equivalent internal event impact, the fire scenario end state was eliminated from further consideration. (The original screening evaluation used a criterion of 10% for this comparison. The bases for that criterion are discussed in the response to Question 6. The 1% criterion used for this analysis provides a substantially larger margin of conservatism in this step of the process, but it does not significantly affect the overall results.) A "yes" in the third column of Table 4-9 indicates that the particular end state requires further evaluation in the next level of screening; a "no" in this column indicates that the end state has been eliminated at this level. None of the end states for fire scenario Z004-FS-01 were eliminated at the first level of quantitative screening.

<u>Task 6.</u> Second Level of Scenario Screening Evaluation

None of the end states from fire scenario Z004-FS-01 lead directly to core damage. In every case, additional system failures must occur before the fire-induced scenario can damage the core. The number, types, and combinations of these additional failures depend on the specific impacts caused by the fire scenario end state. The second level of the quantitative screening process evaluated the dominant conditional system failures that must occur to achieve core damage during each fire scenario end state that survived the first level of screening. This process requires a thorough understanding of the STP PSA event models, systems analyses, and human reliability analyses. The evaluations for this analysis of fire scenario Z004-FS-01 are based on the detailed results from the internal events analyses documented in the STP PSA final report. (The original fire scenario evaluations were based on the results from intermediate versions of the internal events quantification.)

The evaluations for two of the end states from fire scenario Z004-FS-01 are used to illustrate this level of the screening process. The end states are number 11 (a transient initiating event with failure of AC power Train A, DC power train A, and the PDP) and number 19 (a nonisolable small LOCA initiating event with failure of AC power Train A, DC power Train A, and the PDP). Table 4-10 summarizes the dominant additional system failures that must occur for end state 11 to progress to core damage; Table 4-11 provides the corresponding information for end state 19.

The detailed fire impacts on individual power and control cables shown in Table 4-1 were carefully reexamined during this level of the screening process. Notes that address conservatisms in the original impact analysis assumptions for end state 11 are documented in Attachment 4.1 to this response. One of the more important pieces of information that was discovered during this reexamination was that it is necessary to have a fire-induced sustained short circuit in the PDP control cable in order to disable the PDP. The preceding steps of this analysis shown in Tables 4-3 through 4-5 and Figure 4-1 had conservatively assumed that an open circuit in this cable would disable the PDP. Therefore, the evaluations in Attachment 4.1 and Table 4-10 account for the conditional likelihood that the fire will cause a sustained short circuit in this cable.

Table 4-10 shows that the total core damage frequency from the dominant event sequences initiated by fire scenario Z004-FS-01 end state 11 is approximately 1.25E-06 per year. Table 4-11 shows that the corresponding core damage frequency for end state 19 is approximately 7.42E-08 per year. Section 2 of the STP PSA final report notes that the total frequency of core damage from internal events is approximately 1.7E-04 per year. For the second level of this screening evaluation, a fire scenario end state was eliminated from further consideration if its total core damage frequency was less than one-tenth of one percent of the total core damage frequency from internal events; i.e., less than 1.7E-07 per year. (The original screening evaluation used a criterion of 2.0E-07 for this comparison. The bases for that criterion are discussed in the response to Question 5. The small differences between these criteria do not significantly affect the overall results from the evaluation process.) Based on this criterion, fire scenario Z004-FS-01 end state 19 was eliminated from further consideration as a measurably important contributor to STP core damage. This determination is documented by the "no" for end state 19 in the fourth column of Table 4-9. Fire scenario Z004-FS-01 end state 11 could not be eliminated at the second level of quantitative screening. (In addition to end state 19, Table 4-9 shows that end states 15, 16, and 20 were also eliminated at this level of screening; end states 11 and 12 were retained for further evaluation in the third level of screening.)

<u>Task 7.</u> Third Level of Scenario Screening Evaluation

In the third level of the screening analysis, specialized reduction factors were developed to account for the fire zone geometry and the severity of fires necessary to damage critical sets of equipment and cables. The evaluation of end state 11 from fire scenario Z004-FS-01 is used to illustrate this level of the screening process. The information in Table 4-10 was first reviewed to identify the critical sets of fire-induced component failures that dominate the core damage event sequences initiated by this end state. Tables 4-1 through 4-4 were then used to identify the corresponding cables and failure modes that disable each set of components. It was determined that a relatively small set of fire-induced component failures dominates the core damage frequency from end state 11. These failures include auxiliary feedwater (AFW) Train A, essential cooling water (ECW) Train A, component cooling water (CCW) Train A, pressurizer PORV 655A, the positive displacement charging pump (PDP), and selected combinations of these components. Table 4-12 documents the critical cables for these components and identifies the specific fire frequency reduction factors to be developed for this analysis.

The derivation of the reduction factors for fire scenario Z004-FS-01 end state 11 is documented in Attachment 4.2 to this Response. The results are summarized in Table 4-13. Each reduction factor represents the approximate conditional frequency that any fire in zone Z004 damages the identified set of components. All other impacts from the fire are assumed to remain the same as in the preceding levels of the analysis. For example, from Table 4-13, the value of the reduction factor for AFW Train A is 0.15. This means that approximately 15% of the fires in zone Z004 will damage at least one of the critical sets of AFW Train A components listed in Table 4-12. Approximately 2.3% of the fires will disable both AFW Train A and pressurizer PORV 655A. However, except for the components identified in Table 4-12, it is still assumed for this level of screening that every fire in zone Z004 disables all the other baseline components listed in Table 4-6.

The appropriate fire frequency reduction factors were next applied to each of the conditional core damage event sequences from Table 4-10. The modified sequences are shown in Table 4-14. In most cases, application of a reduction factor required subdivision of the original sequence to account for the complete set of possible fire-induced and independent failures. For example, in the first sequence from Table 4-10, it is assumed that the fire disables both AFW Train A and pressurizer PORV 655A. Core damage will occur if independent failures disable AFW Trains B, C, and D. The first sequence in Table 4-14 accounts for the fraction of fires that disable only pressurizer PORV 655A. Under these conditions, core damage will occur if independent failures disable AFW Trains A, B, C, and D. The second sequence in Table 4-14 accounts for the fraction of fires that disable only AFW Train A. In this case, core damage will occur if independent failures disable AFW Trains B, C, and D, and the operators fail to initiate bleed and feed core cooling. Finally, the third sequence in Table 4-14 accounts for the fraction of fires that disable both AFW Train A and pressurizer PORV 655A. This impact is equivalent to the original first sequence from Table 4-10. The remaining sequences in Table 4-14 are derived from Table 4-10 in a similar manner.

Table 4-14 shows that the revised total core damage frequency from the dominant event sequences initiated by fire scenario Z004-FS-01 end state 11 is approximately 1.63E-07 per year. The same screening criteria were used in this level of the analysis as in Task 6 for the second level of screening; i.e., a fire scenario end state was eliminated from further consideration if its total core damage frequency was less than 1.7E-07 per year. Based on this criterion, fire scenario Z004-FS-01 end state 11 was finally eliminated from further consideration as a measurably important contributor to STP core damage and was not formally propagated through the STP event tree quantification. Fire scenario Z004-

FS-01 end state 12 was also eliminated from further consideration at this level of the screening process.

It must be emphasized that this successive screening process was designed to systematically examine every potentially important fire zone in the South Texas plant, to efficiently identify those fires that could be quantitatively significant to the frequency of core damage and plant risk, and to clearly document the bases for eliminating all other zones from the formal event tree quantification process. This process was not designed to precisely quantify the total frequency of core damage that may be attributed to all possible fires in the plant. The process has ensured that all potentially important fires are represented in the final STP PSA results. Several conservatisms remained in the analyses of each end state when it was screened from further consideration and, therefore, each end state frequency can be interpreted only as an upper bound for its contribution to the total. In most cases, detailed analyses that account for the precise routing of all cables in the zone, the actual functions provided by each control cable, information about the relative timing of fire-induced failures and independent component failures, additional fire geometry and severity information, and the effects from efforts to extinguish the fire would be expected to show that the actual core damage contribution from these scr ned fires is vanishingly small.

Table 4-1. Fire Scenario Z004-FS-01

******* **

BUILDING : Electrical Auxiliary Building

LOCATION NAME : ESF-A Switchgear Room

LOCATION DESIGNATOR : Z004

SCENARIO DESIGNATOR : Z004-FS-01

1) HAZARD TYPE : FS Fire and Smoke

2) SOURCE TYPE : CC Control Cable
EC Electrical Cabinet
IC Instrumentation Cable
LC Load Center
MC Motor Control Center
PC Power Cable
RC Relay Cabinets
SW Switchgear
TR Transient Fuel
XR Transformer

3) SCENARIO INITIATION : A FIRE FROM ANY OF THE SOURCES IN 2).

4) PATH OF PROPAGATION
a- PATH TYPE : LOCALIZED. b- PROPAGATION TO : NONE

5) MITIGATING FEATURES :

6) ADDITIONAL SCENARIO DETAIL :

THE FIRE IS RESTRICTED TO THIS ZONE. THE FIRE IS DETECTED AND SUPPRESSED BY THE SPRINKLER SYSTEM OR BY EQUIPMENT IN Z016. THE ADJACENT CORRIDOR. SMOKE/HOT GASES DO NOT DAMAGE EQUIPMENT IN THE CORRIDOR.

7) SCENARIO FREQUENCY : 1.33E-3/YR.

8) PRA EQUIPMENT AFFECTED :

EQUIP ID	EQUIP TYPE		CROSS REFERENCE
AFFN20001-CC	CC Control Cable	YES	SAFW11
AFFN20001-PC	PC Power Cable	YES	SAFW11
AFFN20004-CC	CLC Control Cable	YES	SAFW14
AFFN20004-PC	PC Power Cable	YES	SAFW14
AFPM50001-PC	PC Power Cable	YES	SAFW11
AFVA07517-CC	CC Control Cable	YES	************* MISSING ****************
AFVCS0048-CC	CC Control Cable	YES	SAFW11
AFVCS0048-PC	PC Power Cable	YES	SAFW11
AFVM07525-CC	CC Control Cable	YES	SAFW11
AFVM07525-PC	PC Power Cable	YES	SAFW11
CCAHU0001-CC	CC Control Cable	YES	SCCWA
CCAHU0001-PC	PC Power Cable	YES	SCCWA
CCPM00101ACC	CC Control Cable	YES	SCCWA
CCPM00101APC	PC Power Cable	YES	SCCWA
CCVA04531-CC	CC Control Cable	YES	SRHXA

Table 4-1 (Part 2 of 4). Fire Scenario Z004-FS-01

CCVM00012-CC	CC Control Cable	YES SRHXA
CCVM00012-PC	PC Power Cable	YES SRHXA
CCVM00050-CC	CC Control Cable	YES SRHXA
CCVM00050-PC	PC Power Cable	YES SRHXA
CCVM00052-CC	CC Control Cable	YES 01-PCC
CCVM00052-PC	PC Power Cable	YES 01-PCC
CCVM00057-CC	CC Control Cable	YES SFC11A, SFC12A
CCVM00057-PC	PC Power Cable	YES SFC11A, SFC12A
CCVM00059-CC	CC Control Cable	YES SFC11A, SFC12A
CCVM00059-PC	PC Power Cable	YES SFC11A, SFC12A
CCVM00060-CC	CC Control Cable	YES SFC12A
CCVM00060-PC	PC Power Cable	YES SFC12A
CCVM00063-CC	CC Control Cable	YES SFC12A
CCVM00063-PC	PC Power Cable	YES SFC12A
CCVM00064-CC	CC Control Cable	YES SFC11A
CCVM00064-PC	PC Power Cable	YES SFC11A
CCVM00067-CC	CC Control Cable	YES SFC11A
CCVM00067-PC	PC Power Cable	YES SFC11A
CCVM00069-CC	CC Control Cable	YES SFC11A, SFC12A
CCVM00069-PC	PC Power Cable	YES SFC11A, SFC12A
CCVM00070-CC	CC Control Cable	YES SFC11A, SFC12A
CCVM00070-PC	PC Power Cable	YES SFC11A, SFC12A
CCVM00208-CC	CC Control Cable	YES SFC11C, SFC12C
CCVM00208-PC	PC Power Cable	YES SFC11C, SFC12C
CCVM00235-CC	CC Control Cable	YES CCW-(13)
CCVM00235-PC	PC Power Cable	YES CCW-(13)
CCVM00271-CC	CC Control Cable	YES 01-TDC
CCVM00271-PC	PC Power Cable	YES 01-TDC
CCVM00316-CC	CC Control Cable	YES 01-PCC
CCVM00316-PC	PC Power Cable	YES 01-PCC
CCVM00542-CC	CC Control Cable	YES 01-TDC
CCVM00542-PC	PC Power Cable	YES 01-TDC
CCVM00642-CC	CC Control Cable	YES SCCWA
CCVM00642-PC	PC Power Cable	YES SCCWA
CCVM00643-CC	CC Control Cable	YES SCCWA
CCVM00643-PC	PC Power Cable	YES SCCWA
CCVM00768-CC	CC Control Cable	YES 01-CPC
CCVM00768-PC	PC Power Cable	YES 01-CPC
CCVM00772-CC	CC Control Cable	YES 01-CPC
CCVM00772-PC	PC Power Cable	YES 01-CPC
CHAHU0019-CC	CC Control Cable	YES SECHA
CHAHU0019-PC	PC Power Cable	YES SECHA
CHCHL0001-CC	CC Control Cable	YES SECHA
CHCHL0001-PC	PC Power Cable	YES SECHA
CHCHL0004-CC	CC Control Cable	YES SECHA
CHCHL0004-PC	PC Power Cable	YES SECHA
CHPM00004-CC	CC Control Cable	YES SECHA
CHPM00004-PC	PC Power Cable	YES SECHA
CHVA02477ACC	CC Control Cable	YES SEADA
CHVA02477BCC	CC Control Cable	YES ************* MISSING ****************
CNESFPRESA	IC Instrumentation Cable	YES INSTRU
CSPMS0101APC	PC Power Cable	YES CNSPRYA
CSVM00001ACC	CC Control Cable	YES CNSPRYA
CVAHU0005-CC	CC Control Cable	YES 01-PD
CVAHU0005-PC	PC Power Cable	YES 01-PD
CVPM00101BCC	CC Control Cable	YES 01-PD
CVPM00101BPC	PC Power Cable	YES 01-PD

Table 4-1 (Part 3 of 4). Fire Scenario Z004-FS-01

TABLE D-6 (continued)

CVPMOO102ACC	CC Control Cable	YES	OI-PDP
CVVAOO205-CC	CC Control Cable	YES	OI-CHG
CVVMOOOO3-CC	CC Control Cable	YES	OI-CHG
CVVMOOOO3-PC	PC Power Cable	YES	OI-CHG
CVVMOOO12-CC	CC Control Cable	YES	OI-LDI
CVVMOOO12-PC	PC Power Cable	YES	OI-LDI
CVVMOOO25-CC	CC Control Cable	YES	OI-CHG
CVVMOOO25-PC	PC Power Cable	YES	OI-CHG
CVVMOO465-CC	CC Control Cable	YES	OI-LDI
CVVMOO465-PC	PC Power Cable	YES	OI-LDI
CVVMO8377DCC	CC Control Cable	YES	OI-PB
CVVMO8377DPC	PC Power Cable	YES	OI-PB
DCDCSO134-CC	CC Control Cable	YES	SDG11
DCDCSO134-PC	PC Power Cable	YES	SDG11
DCFN20001-CC	CC Control Cable	YES	SDG11
DCFN20001-PC	PC Power Cable	YES	SDG11
DJDCHOOO1APC	PC Power Cable	YES	SE1A11
DJDCHOOO1DPC	PC Power Cable	YES	SE1D11
DJDCHOOO2APC	PC Power Cable	YES	SE1A11
DJDCHOOO2DPC	PC Power Cable	YES	SE1D11
DJDTROOO1APC	PC Power Cable	YES	SE1A11
EWFN20001-CC	CC Control Cable	YES	SECWA
EWFN20002-CC	CC Control Cable	YES	SECWA
EWPMOO101ACC	CC Control Cable	YES	SECWA
EWPMOO101APC	PC Power Cable	YES	SECWA
EWSC20101ACC	CC Control Cable	YES	SECWA
EWVMOO121-CC	CC Control Cable	YES	SECWA
FWVE17141-CC	CC Control Cable	YES	FW1A
FWVE17142-CC	CC Control Cable	YES	FW1B
FWVE17143-CC	CC Control Cable	YES	FW1C
FWVE17144-CC	CC Control Cable	YES	FW1D
HCFN10001-CC	CC Control Cable	YES	SFC11A
HCFN10001-PC	PC Power Cable	YES	SFC11A
HCFN10002-CC	CC Control Cable	YES	SFC12A
HCFN10002-PC	PC Power Cable	YES	SFC12A
HCVMOOOO1-CC	CC Control Cable	YES	CNISOL
HCVMOOOO1-PC	PC Power Cable	YES	CNISOL
HCVMOOOO6-CC	CC Control Cable	YES	CNISOL
HCVMOOOO6-PC	PC Power Cable	YES	CNISOL
HEFN20001-CC	CC Control Cable	YES	SEADA
HEFN20001-PC	PC Power Cable	YES	SEADA
HEFN20014-CC	CC Control Cable	YES	SEABA
HEFN20014-PC	PC Power Cable	YES	SEADA
HEVAO9649-CC	CC Control Cable	YES	SEABA
HEVAO9650-CC	CC Control Cable	YES	SEADA
HEVAO9651-CC	CC Control Cable	YES	SEADA
HEVAO9656-CC	CC Control Cable	YES	SEADA
HEVAO9657-CC	CC Control Cable	YES	SEADA
MSVAO7414-CC	CC Control Cable	YES	MSIVA
MSVAO7414-PC	PC Power Cable	YES	MSIVA
MSVAO7424-CC	CC Control Cable	YES	MSIVB
MSVAO7434-CC	CC Control Cable	YES	MSIVC
MSVAO7444-CC	CC Control Cable	YES	MSIVD
MSVR37411-CC	CC Control Cable	YES	SCPORVA
MSVR37411-PC	PC Power Cable	YES	SCPORVA
PKSB1E1A	SW Switchgear	YES	************* MISSING ****************
PKSWCOOO1A	SW Switchgear	YES	************* MISSING ****************

Table 4-1 (Part 4 of 4). Fire Sceraio Z004-FS-01

PLLCN0001A	LC Load Center	YES SEIA
PLLCN0001ACC	CC Control Cable	YES SEIA
PLLCN0001APC	PC Power Cable	YES SEIA
PLLCN0002A	LC Load Center	YES SEIA
PLLCN0002ACC	CC Control Cable	YES SEIA
PLLCN0002APC	PC Power Cable	YES SEIA
PMMCC0001A	MC Motor Control Center	YES SEIA
PMMCC0001APC	PC Power Cable	YES SEIA
PMMCC0002A	MC Motor Control Center	YES SEIA
PMMCC0002APC	PC Power Cable	YES SEIA
PMMCC0003APC	PC Power Cable	YES SECWA
PMMCC0004A	MC Motor Control Center	YES SEIA
PMMCC0004APC	PC Power Cable	YES SEIA
PNCAB011B	RC Relay Cabinets	YES ************* MISSING ****************
RCVM00001ACC	CC Control Cable	YES P655
RCVM00001APC	PC Power Cable	YES P655
RCVS00655ACC	CC Control Cable	YES P655
RCVS03657ACC	CC Control Cable	YES HVDT
RCVS03658ACC	CC Control Cable	YES HVDT
RHVA00864-CC	CC Control Cable	YES SLHSIA
SIAHU0006-CC	CC Control Cable	YES ************* MISSING ****************
SIPMS0101APC	PC Power Cable	YES SHHSIA
SIPMS0102APC	PC Power Cable	YES SLHSIA
SIVA00851-CC	CC Control Cable	YES SLHSIA
SIVM00001ACC	CC Control Cable	YES SECCSA
SIVM00004ACC	CC Control Cable	YES SHHSIA
SIVM00004APC	PC Power Cable	YES SHHSIA
SIVM00006ACC	CC Control Cable	YES SHHSIA
SIVM00006APC	PC Power Cable	YES SHHSIA
SIVM00008ACC	CC Control Cable	YES SHHSIA
SIVM00008APC	PC Power Cable	YES SHHSIA
SIVM00011ACC	CC Control Cable	YES SHHSIA
SIVM00011APC	PC Power Cable	YES SHHSIA
SIVM00012ACC	CC Control Cable	YES SHHSIA
SIVM00012APC	PC Power Cable	YES SHHSIA
SIVM00013ACC	CC Control Cable	YES SLHSIA
SIVM00013APC	PC Power Cable	YES SLHSIA
SIVM00014ACC	CC Control Cable	YES SLHSIA
SIVM00014APC	PC Power Cable	YES SLHSIA
SIVM00016ACC	CC Control Cable	YES SRECIA
SIVM00018ACC	CC Control Cable	YES SLHSIA
SIVM00018APC	PC Power Cable	YES SLHSIA
SIVM00031ACC	CC Control Cable	YES SLHSIA
SIVM00031APC	PC Power Cable	YES SLHSIA

9) CONSIDERED FOR FURTHER ANALYSIS : DEFERRED TO QUANTITATIVE SCREENING

10) CLASS : 1 3

11) GUIDELINES : 6

12) REMARKS : SAME AS Z004-EX-01

13) IMPACT CATEGORY : LLA

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Table 4-2. Open Circuit Effects for Fire Scenario Z004-FS-01

Initiating Event	Loss of Main Feedwater to all Steam Generators with Coincident Closure of all MSIVs
Support Systems	AC Train A Failed DC Train A Failed ECW Train A Failed CCW Train A Failed ECH Train A Failed (see Note 1 in Table 4-4) EAB HVAC Train A Failed (see Note 1 in Table 4-4) DC Train D Battery Chargers Failed
Secondary Heat Removal	MSIVs Closed Steam Generator A PORV Fails to Open AFW Train A Failed
RCS Heat Removal	HHSI Train A Failed Bleed and Feed Cooling Failure Caused by Pressurizer PORV 655A Fails to Open
RCS Inventory Control	HHSI Train A Failed LHSI Train A Failed Charging Pump B Failed (see Note 2 in Table 4-4) Positive Displacement Charging Pump Failed (see Note 2 in Table 4-4) Pressurizer PORV 655A Block Valve MOV0001A Fails to Close
Recirculation Cooling	HHSI Train A Failed LHSI Train A Failed RCFC Train A Failed Recirculation Suction Valve MOV0016A Fails to Open
Containment Heat Removal	LHSI Train A Failed RCFC Train A Failed
Fission Product Scrubbing	CS Train A Failed RCFC Train A Failed
Containment Isolation	Supplemental Purge Supply Isolation Valve MOV0001 Fails to Close Supplemental Purge Return Isolation Valve MOV0006 Fails to Close

Table 4-3. Short Circuit Effects for Fire Scenario Z004-FS-01

Initiating Event	Low Pressurizer Pressure Safety Injection from Open Pressurizer PORV 655A
Support Systems	ECW Trin A Failed CCW Train A Failure Caused by Trip of Pump A, Opening of MOV0642, and Closure of MOV0643 ECH Train A Failed (see Note 1 in Table 4-4) EAB HVAC Train A Failed (see Note 1 in Table 4-4)
Secondary Heat Removal	AFW Train A Failure Caused by Closure of MOV7525
RCS Heat Removal	HHSI Train A Failure Caused by Closure of MOV0004A and MOV0006A Bleed and Feed Coling Failure Caused by Closure of Pressurizer PORV 655A Block Valve MOV0001A Pressurizer PORV 655A Opens
RCS Inventory Control	HHSI Train A Failure Caused by Closure of MOV0004A and MOV0006A LHSI Train A Failure Caused by Closure of AOV0864, MOV0018A, and MOV0031A Pressurizer PORV 655A Opens (see Note 3 in Table 4-4) Loss of ECCS Train A Suction from RWST Caused by Closure of MOV0001A Charging Pump B Failure Caused by Closure of MOV8377B (see Note 2 in Table 4-4) Letdown Orifice Block Valve MOV0012 Opens (see Note 4 in Table 4-4) Loss of Normal Charging Flow Caused by Closure of AOV0205, MOV0025, and MOV0003 (see Note 5 in Table 4-4) Reactor Vessel Head Vent Valves SOV3657A and SOV3658A Open (see Note 6 in Table 4-4)

Table 4-3. (Part 2 of 2) Short Circuit Effects for Fire Scenario Z004-FS-01

Recirculation Cooling	HHSI Train A Failure Caused by Closure of MOV004A and MOV0006A LHSI Train A Failure Casued by Opening of AOV0851 and Closure of AOV0864, MOV0018A, and MOV0031A RCFC Train A Failed
Recirculation Cooling (continued)	Loss of CCW Flow to RHR Train A Caused by Closure of AOV4531, MOV0012, and MOV0050 Loss of Cooling Flow to RCFC Train A Caused by Closure of MOV0060, MOV0063, MOV0064, and MOV0067 Loss of Cooling Flow to RCFC Train C Caused by Closure of MOV0208
Containment Heat Removal	Same Impacts as Recirculation Cooling
Fission Product Scrubbing	RCFC Train A Failed CS Train A Failure Caused by Closure of MOV0001A
Containment Isolation	Supplemental Purge Supply Isolation Valve MOV0001 Opens Supplemental Purge Return Isolation Valve MOV0006 Opens

Table 4-4. Assumptions and Thoughts Underlying the Failures Noted for Fire Scenario Z004-FS-01

1. Operators must start ECW Train C, ECH Train C, and EAB HVAC Train C to maintain at least two trains of EAB HVAC running with 600 tons chiller capacity available.

2. Charging Pump B disabled by open circuits in pump power and control cables and by open circuits in room cooler power and control cables. PDP disabled by open circuit in pump control cable. Open circuits cause letdown stop valve LCV0465 to remain open. A letdown line LOCA (outside containment) will occur if Charging Pump A fails and LCV0468, MOV0013, MOV0023, and MOV0024 fail to close; a letdown line LOCA (inside containment) will occur if Charging Pump A fails, MOV0023 or MOV0024 closes, and LCV0468 and MOV0013 fail to close. An RCP seal return line LOCA will occur if Charging Pump A fails and MOV0077 and MOV0079 fail to close. The conditional likelihood of a LOCA is

   (CHA)[(LCV0468)(MOV0013) + (MOV0077)(MOV0079)]

   where

   CHA = Unavailability of Charging Pump A
   LCV0468 = Letdown Line Stop Valve LCV0468 Fails to Close
   MOV0013 = Letdown Orifice Block Valve MOV0013 Fails to Close
   MOV0077 = Seal Return Line Isolation Valve MOV0077 Fails to Close
   MOV0079 = Seal Return Line Isolation Valve MOV0079 Fails to Close

3. Opening of Pressurizer PORV 655A caused by short circuit in valve control cable. If AC Train A load centers E1A1 and E1A2 are deenergized at the time of the initiating event, the operators cannot isolate the open PORV by closing block valve MOV0001A. PORV 655A is powered from DC bus E1A11. It fails to the closed position on loss of power. Therefore, this fire scenario cannot cause a sustained short circuit that keeps PORV 655A open for an extended period of time (i.e., a small LOCA) with simultaneous loss of all power from DC bus E1A11. If the short circuit occurs first, the conditional likelihood of a LOCA after loss of AC and DC power is

   (PO655A)

   where

   PO655A = PORV 655A Fails to Reclose After Loss of DC Power

Table 4-4. (Part 2 of 2) Assumptions and Thoughts Underlying the Failures Noted For Fire Scenario Z004-FS-01

4. Refer to Note 2 above. Since letdown orifice block valve MOV0012 is in parallel with block valve MOV0013, the status of MOV0013 does not affect the likelihood of a letdown line LOCA if MOV0012 is open. The conditional likelihood of a LOCA is

   (CHA)[(LCV0468) + (MOV0077)(MOV0079)]

5. Normal RCP seal injection flow remains available if charging flow control valve AOV0205 closes, charging line containment isolation valve MOV0025 closes, or normal charging valve MOV0003 closes. If AOV0205 is closed, the operators can restore charging flow by locally opening manual bypass valve CV0255. If MOV0003 is closed, the operators can restore charging flow by opening alternate charging valve MOV0006. Normal charging flow cannot be restored of MOV0025 is closed. Refer to Notes 2 and 4 above. If MOV0025 is closed, or if the operators fail to restore flow through the bypass lines, a letdown line LOCA will occur if LCV0468 fails to close. Charging Pump A remains available for normal RCP seal injection flow. The conditional likelihood of a LOCA is

   (LCV0468) + (CHA)(MOV0077)(MOV0079)

6. Reactor head vent valves SOV3657A and SOV3658A open from short circuits in their control cables. A LOCA will not occur unless one of the two normally-closed vent valves SOV0601 or SOV0602 is also opened.

Table 4-5. Frequencies of Internal Events with the Same Combined Impact as Fire Scenario Z004-FS-01

Open Circuit Effects

General Transient Initiating Event Frequency:	4.3/yr
Unavailability of AC Train A:	2.85E-04
Unavailability of Bleed and Feed Cooling:	4.80E-02
Unavailability of PDP (Excluding TSC Diesel):	9.30E-02
"Independent" Scenario 1 Frequency:	5.47E-06/yr
Loss of DC Bus E1A11 Initiating Event Frequency:	3.32E-03/yr
Unavailability of PDP (Excluding TSC Diesel):	9.30E-02
"Independent" Scenario 2 Frequency:	3.09E-04/yr
Loss of Offsite Power Initiating Event Frequency:	1.29E-01/yr
Unavailability of AC Train A (After Recovery):	~ 3.0 E-02
Unavailability of Bleed and Feed Cooling:	4.80E-02
Unavailability of PDP (Including TSC Diesel):	1.95E-01
"Independent" Scenario 3 Frequency:	3.62E-05/yr

Short Circuit Effects

Loss of DC Bus E1A11 Initiating Event Frequency:	3.32E-03/yr
Unavailability of PDP (Excluding TSC Diesel):	9.30E-02
Unavailability of RCFC Train C:	8.84E-02
"Independent" Scenario 1 Frequency:	2.73E-05/yr
Nonisolable Small LOCA Initiating Event Frequency:	5.83E-03/yr
Unavailability of AC Train A:	2.85E-04
Unavailability of RCFC Train C:	8.84E-02
"Independent" Scenario 2 Frequency:	1.47E-07/yr

Table 4-6. Baseline Failures for Fire Scenario Z004-FS-01

Baseline Initiating Event	Loss of Essential DC Bus E1A11
Baseline System Failures	AC Power Train A DC Power Train A ECW Train A CCW Train A ECH Train A EAB HVAC Train A Steam Generator A PORV Fails to Open AFW Train A HHSI Train A LHSI Train A RCFC Train A CS Train A Charging Pump B Recirculation Suction Valve MOV0016A Fail to Open Pressurizer PORV 655A Block Valve MOV0001A Fails to Close Letdown Orifice Block Valve MOV0012 Opens Reactor Vessel Head Vent Valves SOV3657A and SOV3658A Open Supplemental Purge Supply Isolation Valve MOV0001 Opens Supplemental Purge Return Isolation Valve MOV0006 Opens

Table 4-7. Event Tree End State Impacts for Fire Scenario Z004-FS-01 (Refer to Figure 4-1 and Table 4-6)

End State	Failed Equipment Impact
1	Baseline
2	Baseline, RCFC C
3	Baseline, PDP
4	Baseline, RCFC C, PDP
5	Baseline, Loss of Charging
6	Baseline, Loss of Charging, RCFC C
7	Baseline, Loss of Charging, PDP
8	Baseline, Loss of Charging, RCFC C, PDP
9	Baseline, Loss of Bleed and Feed
10	Baseline, Loss of Bleed and Feed, RCFC C
11	Baseline, Loss of Bleed and Feed, PDP
12	Baseline, Loss of Bleed and Feed, RCFC C, PDP
13	Baseline, Loss of Bleed and Feed, Loss of Charging
14	Baseline, Loss of Bleed and Feed, Loss of Charging, RCFC C
15	Baseline, Loss of Bleed and Feed, Loss of Charging, PDP
16	Baseline, Loss of Bleed and Feed, Loss of Charging, RCFC C, PDP
17	Baseline, PORV LOCA
18	Baseline, PORV LOCA, RCFC C
19	Baseline, PORV LOCA, PDP
20	Baseline, PORV LOCA, RCFC C, PD

Table 4-8. Level 1 Screening: Equivalent Internal Event Impacts for End States from Fire Scenario Z004-FS-01

End State	Internal Event Failures	Internal Event Frequency
11	L1DCA, PDH	3.08E-04/yr
12	L1DCA, PDH, CFE	2.72E-05/yr
15	L1DCA, CHC*PDC	1.82E-05/yr
16	L1DCA, CHC*PDC, CFE	1.60E-06/yr
19	SLOCA, EAA+DAA, PDH	4.18E-07/yr
20	SLOCA, EAA+DAA, PDH, CFE	3.70E-08/yr

Split Fraction*	Description	Value
L1DCA	Loss of DC Bus E1A11 Initiating Event	3.320E-03/yr
SLOCA	Nonisolable Small LOCA Initiating Event	5.830E-03/yr
CFE	RCFC Train C Failure	8.835E-02
CHC	Loss of Charging (AC Power Train A Failed)	3.291E-02
DAA	DC Power Train A Failure (AC Power Train A Failed)	4.869E-04
EAA	AC Power Train A Failure (Offsite Power Available)	2.850E-04
PDC	PDP Failure (Excluding TSC Diesel, Loss of Normal Charging)	1.664E-01
PDH	PDP Failure (Excluding TSC Diesel)	9.297E-02

*NOTE: Initiating event frequencies are documented in STP PSA Table 7.6-1. System failure split fractions are documented in STP PSA Appendix F.

Table 4-9. Annual End State Impact Frequencies for Fire Scenario Z004-FS-01 (Total Fire Scenario Frequency: 1.33E-03/yr)

End State	Annual Frequency, Fire-Caused	Annual Frequency, Internal Event	Considered for Further Analysis, First Level of Screening	Considered for Further Analysis, Second Level of Screening
1	0			
2	0			
3	0			
4	0			
5	0			
6	0			
7	0			
8	0			
9	0			
10	0			
11	9.16E-04	3.08E-04	Yes	Yes
12	3.93E-04	2.72E-05	Yes	Yes
13	0			
14	0			
15	3.12E-06	1.82E-05	Yes	No
16	1.34E-06	1.60E-06	Yes	No
17	0			
18	0			
19	1.16E-05	4.18E-07	Yes	No
20	4.99E-06	3.70E-08	Yes	No

Table 4-10. Level 2 Screening: Evaluation of Dominant Additional Failures to Cause Core Damage from Fire Scenario Z004-FS-01 End State 11

End State Frequency: 9.16E-04/yr

Additional Failures to Cause Core Damage:

1. AFW B, AFW C, AFW D
2. ECW B, ECH C, Smoke Purge, (AFW D or PDP)
3. ECW B, Fan C, Smoke Purge, (AFW D or PDP)
4. ECW C, ECH B, Smoke Purge, (AFW D or PDP)
5. ECW C, Fan B, Smoke Purge, (AFW D or PDP)
6. ECW B, ECW C, Smoke Purge, (AFW D or PDP)
7. ECH B, Fan C, Smoke Purge, (AFW D or PDP)
8. ECH C, Fan B, Smoke Purge, (AFW D or PDP)
9. ECH B, ECH C, Smoke Purge, (AFW D or PDP)
10. ECW B, CCW C, PDP
11. ECW C, CCW B, PDP
12. ECW B, ECW C, PDP
13. CCW B, CCW C, PDP

Approximate Conditional Core Damage Frequency:

1.	CDC	3.784E-04
2.	WBE*CLG*OS03*(AFR'+PDJ1)	1.045E-04
3.	WBE*FCN*OS03*(AFR'+PDJ1)	9.969E-05
4.	WCM*CLE*OS03*(AFR'+PDJ1)	2.482E-06
5.	WCM*FBH*OS03*(AFR'+PDJ1)	1.113E-07
6.	W23*OS03*(AFR'+PDJ1)	2.744E-05
7.	CLE*FCN*OS03*(AFR'+PDJ1)	1.199E-05
8.	CLG*FBH*OS03*(AFR'+PDJ1)	5.639E-07
9.	CLD*OS03*(AFR'+PDJ1)	1.197E-05
10.	WBE*K14*PDH1	1.279E-04
11.	WCM*K13*PDH1	1.865E-04
12.	W23*PDH1	2.873E-04
13.	K23*PDH1	1.206E-04

Approximate End State Core Damage Frequency: 1.25E-06/yr

*NOTE: System failure split fractions are documented in STP PSA Appendix F. Operator action split fractions are documented in STP PSA Table 15.4-53. Modifications to PDP split fractions to account for fire-induced control cable hot shorts are documented in Attachment 4.1 to this Response.

Table 4-10. (Part 2 of 2) Level 2 Screening: Evaluation of Dominant Additional Failures to Cause Core Damage from Fire Scenario Z004-FS-01 End State 11

Split Fraction*	Description	Value
AFR'	AFW Train D Failure (After Turbine Recovery)	7.836E-02
CDC	AFW Trains B, C, and D Failure	3.784E-04
CLD	ECH Trains B and C Failure	6.824E-04
CLE	ECH Train B Failure	1.522E-02
CLG	ECH Train C Failure	4.710E-02
FBH	EAB HVAC Fan Train B Failure	6.825E-04
FCN	EAB HVAC Fan Train C Failure	4.491E-02
K13	CCW Train B Failure	1.092E-01
K14	CCW Train C Failure	5.503E-03
K23	CCW Trains B and C Failure	6.563E-04
OS03	Operator Failure to Start Smoke Purge	4.960E-02
PDH1	PDP Failure (Excluding TSC Diesel, Including Control Cable Hot Short)	1.837E-01
PDJ1	PDP Failure (Including TSC Diesel, Including Control Cable Hot Short)	2.754E-01
WBE	ECW Train B Failure	1.265E-01
WCM	ECW Train C Failure	9.296E-03
W23	ECW Trains B and C Failure	1.564E-03

Table 4-11. Level 2 Screening: Evaluation of Dominant Additional Failures to Cause Core Damage from Fire Scenario Z004-FS-01 End State 19

End State Frequency: 1.16E-05/yr

Additional Failures to Cause Core Damage:

1. ECW B, CCW C
2. ECW C, CCW B
3. ECW B, ECW C
4. CCW B, CCW C
5. ECW B, ECH C, Smoke Purge
6. ECW B, Fan C, Smoke Purge
7. ECW C, ECH B, Smoke Purge
8. ECW C, Fan B, Smoke Purge
9. ECH B, Fan C, Smoke Purge
10. ECH C, Fan B, Smoke Purge
11. ECH B, ECH C, Smoke Purge
12. HPI B, HPI C
13. REC B, REC C
14. RCFC B, RCFC C, OL
15. RCFC B, RCFC C, REC B, (LPI C or HX C)
16. RCFC B, RCFC C, REC C, (LPI B or HX B)
17. RCFC B, RCFC C, LPI B, LPI C
18. RCFC B, RCFC C, LPI B, HX C
19. RCFC B, RCFC C, LPI C, HX B
20. RCFC B, RCFC C, HX B, HX C
21. ECW B, RCFC C, OL
22. ECW B, RCFC C, (REC C or LPI C or HX C)
23. CCW B, RCFC C, OL
24. CCW B, RCFC C, (REC C or LPI C or HX C)
25. ECW C, RCFC B, OL
26. ECW C, RCFC B, (REC B or LPI B or HX B)
27. CCW C, RCFC B, OL
28. CCW C, RCFC B, (REC B or LPI B or HX B)

Table 4-11. (Part 2 of 3) Level 2 Screening: Evaluation of Dominant Additional Failures to Cause Core Damage from Fire Scenario Z004-FS-01 End State 19

Approximate Conditional Core Damage Frequency:

1.	WBE*K14	6.961E-04
2.	WCM*K13	1.015E-03
3.	W23	1.564E-03
4.	K23	6.563E-04
5.	WBE*CLG*OS03	2.955E-04
6.	WBE*FCN*OS03	2.818E-04
7.	WCM*CLE*OS03	7.017E-06
8.	WCM*FBH*OS03	3.147E-07
9.	CLE*FCN*OS03	3.390E-05
10.	CLG*FBH*OS03	1.594E-06
11.	CLD*OS03	3.385E-05
12.	HIB+2*PA*HIC+PAB	7.750E-04
13.	RAB	4.548E-04
14.	CFC*OL02	2.002E-05
15.	CFC*RA*(LA+RXC)	2.420E-07
16.	CFC*RA*(LA+RXC)	2.420E-07
17.	CFC*LAB	8.012E-07
18.	CFC*LA*RXC	7.650E-08
19.	CFC*LA*RXC	7.650E-08
20.	CFC*RXB	1.893E-07
21.	WBE*CFE*OL02	7.656E-05
22.	WBE*CFE*(RA+LA+RXC)	2.161E-04
23.	K13*CFE*OL02	6.609E-05
24.	K13*CFE*(RA+LA+RXC)	1.865E-04
25.	WCM*CFD*OL02	2.788E-06
26.	WCM*CFD*(RA+LA+RXC)	7.868E-06
27.	K14*CFD*OL02	1.650E-06
28.	K14*CFD*(RA+LA+RXC)	4.658E-06

Aproximate End State Core Damage Frequency: 7.42E-08/yr

Table 4-11. (Part 3 of 3) Level 2 Screening: Evaluation of Dominant Additional Failures to Cause Core Damage from Fire Scenario Z004-FS-01 End State 19

Split Fraction*	Description	Value
CFC	RCFC Trains B and C Failure	2.922E-03
CFD	RCFC Train B Failure	4.378E-02
CFE	RCFC Train C Failure	8.835E-02
CLD	ECH Trains B and C Failure	6.824E-04
CLE	ECH Train B Failure	1.522E-02
CLG	ECH Train C Failure	4.710E-02
FBH	EAB HVAC Fan Train B Failure	6.825E-04
FCN	EAB HVAC Fan Train C Failure	4.491E-02
HIB	HHSI Trains B and C Failure	2.063E-04
HIC	HHSI Train B (C) Failure	6.864E-03
K13	CCW Train B Failure	1.092E-01
K14	CCW Train C Failure	5.503E-03
K23	CCW Trains B and C Failure	6.563E-04
LA	LHSI Train B (C) Failure	1.041E-02
LAB	LHSI Trains B and C Failure	2.742E-04
OL02	Operator Failure to Depressurize for LHSI (Small LOCA event)	6.850E-03
OS03	Operator Failure to Start Smoke Purge	4.960E-02
PA	ECCS Common Train B (C) Failure	3.799E-02
PAB	ECCS Common Trains B and C Failure	4.714E-05
RA	Recirc. Suction Train B (C) Failure	6.408E-03
RAB	Recirc. Suction Trains B and C Failure	4.548E-04
RXB	RHR Heat Exchanger Trains B and C Failure	6.477E-05
RXC	RHR Heat Exchanger Train B (C) Failure	2.515E-03
WBE	ECW Train B Failure	1.265E-01
WCM	ECW Train C Failure	9.296E-03
W23	ECW Trains B and C Failure	1.564E-03

*NOTE: System failure split fractions are documented in STP PSA Appendix F. Operator action split fractions are documented in STP PSA Table 15.4-53.

Table 4-12. Identification of Fire Frequency Reduction Factors for Fire Scenario Z004-FS-01 End States 11 and 12

FIRE ANALYSIS REDUCTION FACTOR NOTES

ZONE: Z004
LOCATION: ESF-A Switchgear Room
END STATE: 11,12 (Sheet 1)

CRITICAL CABLES: A. Pressurizer PORV 655A control cable (RCVS00655ACC)
Pressurizer PORV 655A Block Valve MOV0001A power cable and control cable (Either: RCVM0001APC or RCVM0001ACC)

B. AFW Pump A circuit breaker
AFW Pump A power cable (AFPMS0001-PC)
AFW Pump A Ventilation Fan motor contactor
AFW Pump A Ventilation Fan power cable and control cable (Either: AFFN20001-PC or AFFN20001-CC)

C. PDP control cable (CVPM00102ACC)

NOTES: 1. We need to estimate the fraction of these fires that will cause each of the following combinations of faults (letter designations refer to sets of cables noted above):

A: An open circuit in the PORV cable, or a sustained hot short in either block valve cable
B: An open circuit in any AFW pump or fan cable
C: A sustained hot short
A and B: Any combination of the faults noted above for A and B

2. The frequency of this end state already accounts for a nominal reduction factor of 0.10 for the conditional frequency of a sustained hot short circuit in the PDP control cable, if it is affected by the fire.

Table 4-12. (Part 2 of 2)Identification of Fire Frequency Reduction Factors for Fire Scenario Z004-FS-01 End States 11 and 12

FIRE ANALYSIS REDUCTION FACTOR NOTES

ZONE: Z004
LOCATION: ESF-A Switchgear Room
END STATE: 11,12 (Sheet 2)

CRITICAL CABLES:

A. ECW Pump A circuit breaker
ECW Pump A power cable and control cable (Either: EWPM00101APC or EWPM00101ACC)
ECW Pump A Ventilation Fans control cables (Both: EWFN20001-CC and EWFN20002-CC)

B. CCW Pump A circuit breaker
CCW Pump A power cable and control cable (Either: CCPM00101APC or CCPM00101ACC)
CCW Pump A Ventilation Fan motor contactor
CCW Pump A Ventilation Fan power cable and control cable (Either: CCAHU0001-PC or CCAHU0001-CC)

C. PDP control cable (CVPM00102ACC)

NOTES:

1. We need to estimate the fraction of these fires that will cause each of the following combinations of faults (letter designations refer to sets of cables noted above):
   - A: An open circuit in the pump cable, or open circuits in both fan cables
   - B: An open circuit in any CCW pump or fan cable
   - C: A sustained hot short
   - A and C: Any combination of the faults noted above for A and C
   - B and C: Any combination of the faults noted above for B and C

2. The frequency of this end state already accounts for a nominal reduction factor of 0.10 for the conditional frequency of a sustained hot short circuit in the PDP control cable, if it is affected by the fire.

Table 4-13. Fire Frequency Reduction Factors for Fire Scenario Z004-FS-01 End States 11 and 12

Components	Designator	Value
AFW Train A	fRED(AFW A)	0.15
ECW Train A	fRED(ECW A)	0.12
CCW Train A	fRED(CCW A)	0.16
Pressurizer PORV 655A	fRED(PORV)	0.023
PDP	fRED(PDP)	0.012
AFW Train A and Pressurizer PORV	fRED(AFW A,PORV)	0.023
ECW Train A and PDP	fRED(ECW A,PDP)	0.012
CCW Train A and PDP	fRED(CCW A,PDP)	0.012

Table 4-14. Level 3 Screening: Evaluation of Dominant Additional Failures to Cause Core Damage from Fire Scenario Z004-FS-01 End State 11

End State Frequency: 9.16E-04/yr

Additional Failures to Cause Core Damage:
1. fRED(PORV), AFW A, AFW B, AFW C, AFW D
2. fRED(AFW A), AFW B, AFW C, AFW D, Bleed+Feed
3. fRED(AFW A,PORV), AFW B, AFW C, AFW D
4. fRED(ECW A), ECW B, ECH C, Smoke Purge, (AFW D or PDP)
5. [1-fRED(ECW A)], ECW A, ECW B, ECH C, Smoke Purge, "X"
6. fRED(ECW A,PDP), ECW B, ECH C, Smoke Purge, (AFW D or PDP1)
7. fRED(ECW A), ECW B, Fan C, Smoke Purge, (AFW D or PDP)
8. [1-fRED(ECW A)], ECW A, ECW B, Fan C, Smoke Purge, "X"
9. fRED(ECW A,PDP), ECW B, Fan C, Smoke Purge, (AFW D or PDP1)
10. ECW C, ECH B, Smoke Purge, "X"
11. ECW C, Fan B, Smoke Purge, "X"
12. fRED(ECW A), ECW B, ECW C, Smoke Purge, (AFW D or PDP)
13. [1-fRED(ECW A)], ECW A, ECW B, ECW C, Smoke Purge, "X"
14. fRED(ECW A,PDP), ECW B, ECW C, Smoke Purge, (AFW D or PDP1)
15. ECH B, Fan C, Smoke Purge, "X"
16. ECH C, Fan B, Smoke Purge, "X"
17. ECH B, ECH C, Smoke Purge, "X"
18. fRED(ECW A), ECW B, CCW C, PDP
19. fRED(CCW A), ECW B, CCW C, PDP
20. [1-fRED(ECW A)-fRED(CCW A)], ECW A, ECW B, CCW C, "Y"
21. [1-fRED(ECW A)-fRED(CCW A)], CCW A, ECW B, CCW C, "Y"
22. fRED(ECW A,PDP), ECW B, CCW C, PDP1
23. fRED(CCW A,PDP), ECW B, CCW C, PDP1
24. fRED(ECW A), ECW C, CCW B, PDP
25. fRED(CCW A), ECW C, CCW B, PDP
26. [1-fRED(ECW A)-fRED(CCW A)], ECW A, ECW C, CCW B, "Y"
27. [1-fRED(ECW A)-fRED(CCW A)], CCW A, ECW C, CCW B, "Y"
28. fRED(ECW A,PDP), ECW C, CCW B, PDP1
29. fRED(CCW A,PDP), ECW C, CCW B, PDP1
30. fRED(ECW A), ECW B, ECW C, PDP
31. fRED(CCW A), ECW B, ECW C, PDP
32. [1-fRED(ECW A)-fRED(CCW A)], ECW A, ECW B, ECW C, "Y"
33. [1-fRED(ECW A)-fRED(CCW A)], CCW A, ECW B, ECW C, "Y"
34. fRED(ECW A,PDP), ECW B, ECW C, PDP1
35. fRED(CCW A,PDP), ECW B, ECW C, PDP1
36. fRED(ECW A), CCW B, CCW C, PDP
37. fRED(CCW A), CCW B, CCW C, PDP
38. [1-fRED(ECW A)-fRED(CCW A)], ECW A, CCW B, CCW C, "Y"
39. [1-fRED(ECW A)-fRED(CCW A)], CCW A, CCW B, CCW C, "Y"
40. fRED(ECW A,PDP), CCW B, CCW C, PDP1
41. fRED(CCW A,PDP), CCW B, CCW C, PDP1

Table 4-14. (Part 2 of 4) Level 3 Screening: Evaluation of Dominant Additional Failures to Cause Core Damage from Fire Scenario Z004-FS-01 End State 11 Notes

NOTE: "X" = AFW D + fRED(PDP)*PDP1 + [1-fRED(PDP)]*PDP
"Y" = fRED(PDP)*PDP1 + [1-fRED(PDP)]*PDP

Table 4-14. (Part 3 of 4) Level 3 Screening: Evaluation of Dominant Additional Failures to Cause Core Damage from Fire Scenario Z004-FS-01 End State 11

Approximate Conditional Core Damage Frequency:

1.	(0.023)*CDA	7.835E-07
2.	(0.15)*CDC*OBA	2.725E-06
3.	(0.023)*CDC	8.701E-06
4.	(0.12)*WBE*CLG*OS03*(AFR'+PDJ)	9.690E-06
5.	(0.88)*W21*CLG*OS03*[AFR'+(0.012)*PDJ1+(0.988)*PDJ]	6.849E-08
6.	(0.012)*WBE*CLG*OS03*(AFR'+PDJ1)	1.255E-06
7.	(0.12)*WBE*FCN*OS03*(AFR'+PDJ)	9.240E-06
8.	(0.88)*W21*FCN*OS03*[AFR'+(0.012)*PDJ1+(0.988)*PDJ]	6.531E-08
9.	(0.012)*WBE*FCN*OS03*(AFR'+PDJ1)	1.196E-06
10.	WCM*CLE*OS03*[AFR'+(0.012)*PDJ1+(0.988)*PDJ]	1.924E-06
11.	WCM*FBH*OS03*[AFR'+(0.012)*PDJ1+(0.988)*PDJ]	8.630E-08
12.	(0.12)*W23*OS03*(AFR'+PDJ)	2.543E-06
13.	(0.88)*W31*OS03*[AFR'+(0.012)*PDJ1+(0.988)*PDJ]	2.361E-08
14.	(0.012)*W23*OS03*(AFR'+PDJ1)	3.293E-07
15.	CLE*FCN*OS03*[AFR'+(0.012)*PDJ1+(0.988)*PDJ]	9.297E-06
16.	CLG*FBH*OS03*[AFR'+(0.012)*PDJ1+(0.988)*PDJ]	4.372E-07
17.	CLD*OS03*[AFR'+(0.012)*PDJ1+(0.988)*PDJ]	9.282E-06
18.	(0.12)*WBE*K14*PDH	7.766E-06
19.	(0.16)*WBE*K14*PDH	1.036E-05
20.	(0.739)*W21*K14*[(0.012)*PDH1+(0.988)*PDH]	4.648E-08
21.	(0.739)*WBE*K24*[(0.012)*PDH1+(0.988)*PDH]	8.237E-08
22.	(0.012)*WBE*K14*PDH1	1.535E-06
23.	(0.012)*WBE*K14*PDH1	1.535E-06
24.	(0.12)*WCM*K13*PDH	1.133E-05
25.	(0.16)*WCM*K13*PDH	1.510E-05
26.	(0.739)*W24*K13*[(0.012)*PDH1+(0.988)*PDH]	8.896E-08
27.	(0.739)*WCM*K21*[(0.012)*PDH1+(0.988)*PDH]	8.258E-08
28.	(0.012)*WCM*K13*PDH1	2.238E-06
29.	(0.012)*WCM*K13*PDH1	2.238E-06
30.	(0.12)*W23*PDH	1.745E-05
31.	(0.16)*W23*PDH	2.326E-05
32.	(0.739)*W31*[(0.012)*PDH1+(0.988)*PDH]	1.372E-07
33.	(0.739)*W23*K11*[(0.012)*PDH1+(0.988)*PDH]	1.235E-07
34.	(0.012)*W23*PDH1	3.448E-06
35.	(0.012)*W23*PDH1	3.448E-06
36.	(0.12)*K23*PDH	7.322E-06
37.	(0.16)*K23*PDH	9.762E-06
38.	(0.739)*WAA*K23*[(0.012)*PDH1+(0.988)*PDH]	4.286E-08
39.	(0.739)*K31*[(0.012)*PDH1+(0.988)*PDH]	2.047E-07
40.	(0.012)*K23*PDH1	1.447E-06
41.	(0.012)*K23*PDH1	1.447E-06

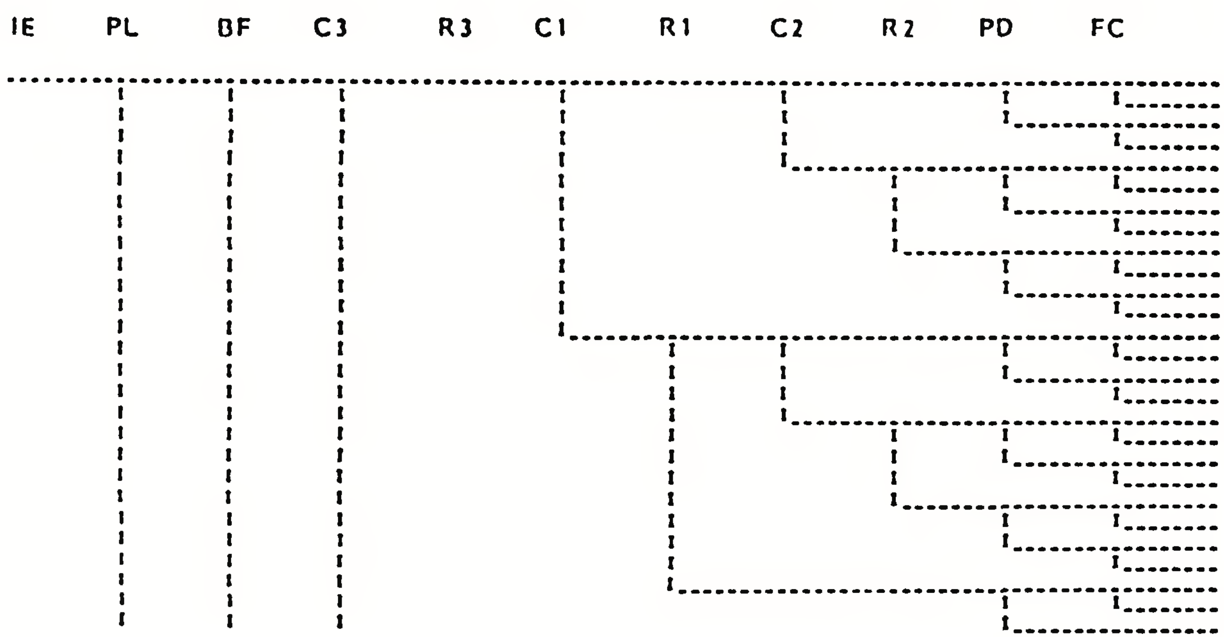
Approximate End State Core Damage Frequency: 1.63E-07/yr

Table 4-14. (Part 4 of 4) Level 3 Screening: Evaluation of Dominant Additional Failures to Cause Core Damage from Fire Scenario Z004-FS-01 End State 11

Split Fraction*	Description	Value
AFR'	AFW Train D Failure (After Turbine Recovery)	7.836E-02
CDA	AFW Trains A, B, C, and D Failure	3.406E-05
CDC	AFW Trains B, C, and D Failure	3.784E-04
CLD	ECH Trains B and C Failure	6.824E-04
CLE	ECH Train B Failure	1.522E-02
CLG	ECH Train C Failure	4.710E-02
FBH	EAB HVAC Fan Train B Failure	6.825E-04
FCN	EAB HVAC Fan Train C Failure	4.491E-02
K11	CCW Train A Failure	1.136E-03
K13	CCW Train B Failure	1.092E-01
K14	CCW Train C Failure	5.503E-03
K21	CCW Trains A and B Failure	1.278E-04
K23	CCW Trains B and C Failure	6.563E-04
K24	CCW Trains A and C Failure	9.368E-06
K31	CCW Trains A, B, and C Failure	2.945E-06
OBA	Bleed and Feed Failure (Transient Event)	4.802E-02
OS03	Operator Failure to Start Smoke Purge	4.960E-02
PDH	PDP Failure (Excluding TSC Diesel)	9.297E-02
PDH1	PDP Failure (Excluding TSC Diesel, Including Control Cable Hot Short)	1.837E-01
PDJ	PDP Failure (Including TSC Diesel)	1.949E-01
PDJ1	PDP Failure (Including TSC Diesel, Including Control Cable Hot Short)	2.754E-01
WAA	ECW Train A Failure	9.394E-04
WBE	ECW Train B Failure	1.265E-01
WCM	ECW Train C Failure	9.296E-03
W21	ECW Trains A and B Failure	1.215E-04
W23	ECW Trains B and C Failure	1.564E-03
W24	ECW Trains A and C Failure	1.172E-05
W31	ECW Trains A, B, and C Failure	1.973E-06

*NOTE: System failure split fractions are documented in STP PSA Appendix F. Operator action split fractions are documented in STP PSA Table 15.4-53. Modifications to PDP split fractions to account for fire-induced control cable hot shorts are documented in Attachment 4.1 to this Response. Specialized fire impact reduction factors are documented in Attachment 4.2 to this Response.

Figure 4-1 (Part 1 of 4). Event Tree for Fire Scenario Z004-FS-01

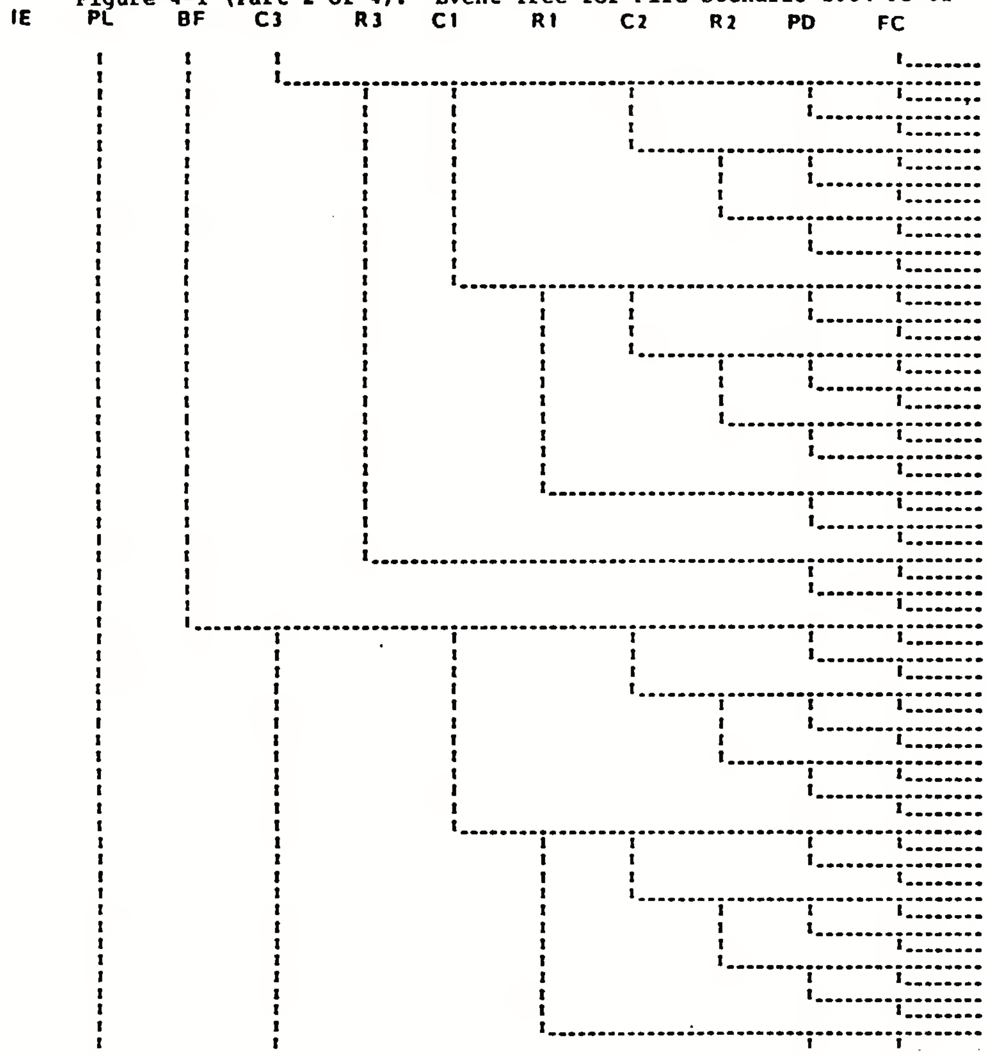


SEQ	END STATE	FREQ.
1	1	0.0000E-01
2	2	0.0000E-01
3	3	0.0000E-01
4	4	0.0000E-01
5	1	0.0000E-01
6	2	0.0000E-01
7	3	0.0000E-01
8	4	0.0000E-01
9	5	0.0000E-01
10	6	0.0000E-01
11	7	0.0000E-01
12	8	0.0000E-01
13	1	0.0000E-01
14	2	0.0000E-01
15	3	0.0000E-01
16	4	0.0000E-01
17	1	0.0000E-01
18	2	0.0000E-01
19	3	0.0000E-01
20	4	0.0000E-01
21	5	0.0000E-01
22	6	0.0000E-01
23	7	0.0000E-01
24	8	0.0000E-01
25	5	0.0000E-01
26	6	0.0000E-01
27	7	0.0000E-01

ATTACHMENT 1

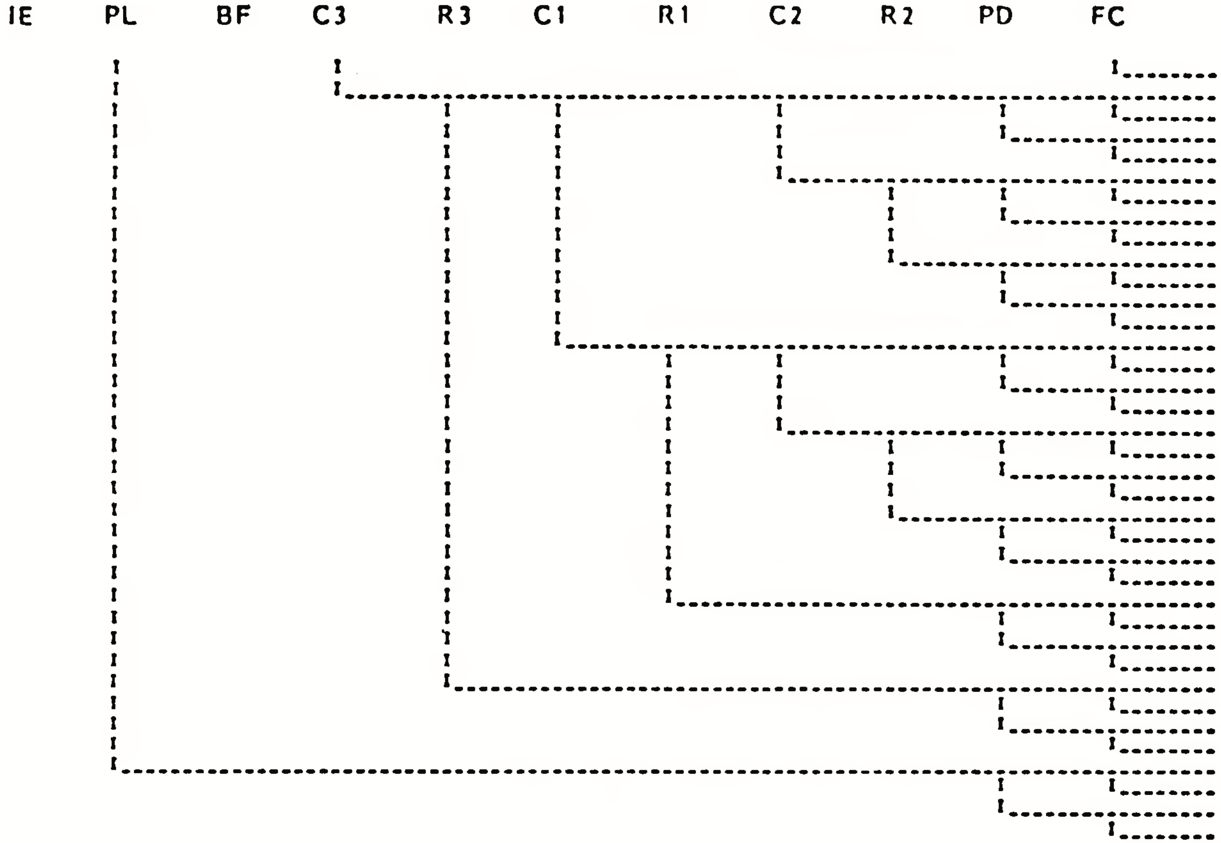
RESPONSES TO STP PSA FIRE RISK QUESTIONS

Figure 4-1 (Part 2 of 4). Event Tree for Fire Scenario Z004-FS-01



SEQ	END STATE	FREQ.
28	8	0.0000E-01
29	1	0.0000E-01
30	2	0.0000E-01
31	3	0.0000E-01
32	4	0.0000E-01
33	1	0.0000E-01
34	2	0.0000E-01
35	3	0.0000E-01
36	4	0.0000E-01
37	5	0.0000E-01
38	6	0.0000E-01
39	7	0.0000E-01
40	8	0.0000E-01
41	1	0.0000E-01
42	2	0.0000E-01
43	3	0.0000E-01
44	4	0.0000E-01
45	1	0.0000E-01
46	2	0.0000E-01
47	3	0.0000E-01
48	4	0.0000E-01
49	5	0.0000E-01
50	6	0.0000E-01
51	7	0.0000E-01
52	8	0.0000E-01
53	5	0.0000E-01
54	6	0.0000E-01
55	7	0.0000E-01
56	8	0.0000E-01
57	5	0.0000E-01
58	6	0.0000E-01
59	7	0.0000E-01
60	8	0.0000E-01
61	9	0.0000E-01
62	10	0.0000E-01
63	11	1.1529E-05
64	12	4.8548E-06
65	9	0.0000E-01
66	10	0.0000E-01
67	11	4.8500E-06
68	12	2.0786E-06
69	13	0.0000E-01
70	14	0.0000E-01
71	15	4.8548E-09
72	16	2.0506E-09
73	9	0.0000E-01
74	10	0.0000E-01
75	11	4.3363E-06
76	12	2.0594E-06
77	9	0.0000E-01
78	10	0.0000E-01
79	11	2.3578E-06
80	12	8.3191E-07
81	13	0.0000E-01
82	14	0.0000E-01
83	15	2.0595E-09
84	16	8.8279E-10
85	13	0.0000E-01
86	14	0.0000E-01

Figure 4-1 (Part 3 of 4). Event Tree for Fire Scenario Z004-FS-01



SEQ	END STATE	FREQ.
88	16	2.9724E-09
89	9	0.0000E-01
90	10	0.0000E-01
91	11	1.1328E-07
92	12	4.8549E-08
93	9	0.0000E-01
94	10	0.0000E-01
95	11	4.8500E-08
96	12	2.0786E-08
97	13	0.0000E-01
98	14	0.0000E-01
99	15	4.8548E-11
100	16	2.0806E-11
101	9	0.0000E-01
102	10	0.0000E-01
103	11	4.9063E-08
104	12	2.0599E-08
105	9	0.0000E-01
106	10	0.0000E-01
107	11	2.0578E-08
108	12	8.8190E-09
109	13	0.0000E-01
110	14	0.0000E-01
111	15	2.0598E-11
112	16	8.8279E-12
113	13	0.0000E-01
114	14	0.0000E-01
115	15	6.9355E-10
116	16	2.9723E-10
117	13	0.0000E-01
118	14	0.0000E-01
119	15	2.3332E-09
120	16	1.0009E-09
121	17	0.0000E-01
122	18	0.0000E-01
123	19	2.9559E-07
124	20	1.2669E-07

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Figure 4-1. (Part 4 of 4) Event Tree for Fire Scenario Z004-FS-01

Top Event	Description of Top Event Failure
PL	PORV LOCA (S)
BF	PORV Not Available for Bleed and Feed (O)
C3	Charging AOV0205 Closed (S)
R3	Operators Fail to Locally Open CV0255 (M)
C1	Charging MOV0025 Closed (S)
R1	Operators Fail to Locally Open MOV0025 (M)
C2	Charging MOV0003 Closed (S)
R2	Operators Fail to Open Alternate Charging MOV0006 (M)
PD	PDP Failed (O)
FC	RCFC C CCW Valve MOV0208 Closed (S)

NOTES: 1. (S) indicates impact from a short circuit
2. (O) indicates impact from an open circuit
3. (M) indicates an operator action

RESPONSE TO QUESTION 4
ATTACHMENT 4.1

NOTES ON SCREENING EVALUATION FOR
FIRE SCENARIO Z004-FS-01 END STATE 11

Fire scenario Z004-FS-01 was initially modeled as disabling essential AC power Train A, essential DC power Train A, and the positive displacement charging pump (PDP). That model conservatively bounded the actual fire impacts for the purposes of the initial screening evaluations. However, specific elements of the bounding model introduced excessive conservatism into the evaluation of End State 11. In particular, this fire does not directly disable the PDP. As noted in the attached list of affected cables, the fire does disable essential AC power Train A and its associated systems. The fire also affects power and control cables for several components throughout the CCW system, the PDP, and pressurizer PORV 655A. The affected components are:

COMPONENT COOLING WATER

MOV0291. The fire damages a power cable and a control cable for normally-open MOV0291 in the CCW supply line to the RCP thermal barrier coolers. This valve is a parallel path to normally-open MOV0318, which is not affected by the fire. (MOV0318 receives power and control signals from essential Train B.) Therefore, even if a fire-induced short circuit causes MOV0291 to close, the impact on thermal barrier cooling is very minor.

MOV0542. The fire damages a power cable and a control cable for normally-open MOV0542 in the CCW return line from the RCP thermal barrier coolers. This valve is a parallel path to normally-open MOV0403, which is not affected by the fire. (MOV0403 receives power and control signals from essential Train B.) Therefore, even if a fire-induced short circuit causes MOV0542 to close, the impact on thermal barrier cooling is very minor.

MOV0208. The fire damages a power cable and a control cable for normally-open MOV0208 in the CCW Train C return line from RCFCs 11C and 12C. An open circuit in either cable will cause the valve to remain open and has no impact on RCFC Train C availability. A fire-induced sustained short circuit may cause the valve to close if it energizes the motor contactor closing direction coil. These control cable faults have no impact on CCW Train C availability. Fire-induced sustained short circuits that close MOV0208 and disable RCFC Train C are modeled explicitly in End States 12, 16, and 20.

MOV0235. The fire damages a power cable and a control cable for normally-open MOV0235 in the CCW supply line to the nonessential cooling loads. This valve is in series with normally-open MOV0236, which is not affected by the fire. (MOV0236 receives power and control signals from essential Train C.) If it is necessary to isolate these cooling loads, MOV0236 remains available to close normally from automatic or remote manual signals. The operators may also locally close MOV0235 using its handwheel. If a fire-induced short circuit causes MOV0235 to close, the operators can deenergize the motor circuit and manually reopen the valve before any of the nonessential loads are restored to service.

POSITIVE DISPLACEMENT CHARGING PUMP

PDP. The fire affects a control cable for the PDP, but does not affect a power cable for the pump. A review of the attached HL&P cable routing information has identified this cable as providing the lube oil pressure interlock signal for PDP operation. Logic Diagram 9R-17-9-Z-42404 (Rev. 7) and Elementary Diagram 9-E-CV30-01 (Rev. 5) show that this interlock circuit is normally open when the pump is running. If the fire causes an open circuit in the cable, the PDP can be started from the control room, and it will continue to run indefinitely. However, it will not trip automatically from a low lube oil pressure condition. If the fire causes a sustained short circuit in the cable, the pump control circuits will sense a false low lube oil pressure signal, and the pump cannot be started. (This signal will also trip the pump if it is already running when the short occurs.) Section 9.3.2 of the STP PSA report notes that a "generic" value of 0.10 is assigned for the conditional frequency of sustained hot shorts in control cables. Therefore, the appropriate conditional frequency for PDP failure in End State 11 is:

PDP Failure = (Sustained Hot Short) OR
(No Hot Short)*(PDP Fails Independently)

If normal AC power is available, this value is:

$$PDH1 = (0.10) + (0.90)*(PDH) = 0.1837$$

If the PDP must be powered from the TSC diesel generator, this value is:

$$PDJ1 = (0.10) + (0.90)*(PDJ) = 0.2754$$

RESPONSES TO STP PSA FIRE RISK QUESTIONS

PRESSURIZER PORV 655A

PORV655A and MOV0001A. The fire damages a control cable for pressurizer PORV 655A and a power cable and a control cable for its normally-open block valve MOV0001A. An open circuit or a short circuit in the PORV control cable may prevent automatic or remote manual operation of the valve and disable the bleed and feed mode of direct core cooling. (The STP PSA event model success criteria require both pressurizer PORVs to be opened for bleed and feed cooling.) End State 11 also includes the impacts from fire-induced sustained short circuits in either cable for PORV block valve MOV0001A. These short circuits may cause the block valve to close if they energize the motor contactor closing direction coil.

The actual equipment failures that occur in fire scenario 2004-FS-01 End State 11 are:

Essential AC Train A
Essential DC Train A
Pressurizer PORV 655A

RESPONSE TO QUESTION 4
ATTACHMENT 4.2

REDUCTION FACTOR ANALYSIS

ZONE: Z004

CONTENTS:
1 4160V Switchgear-E1A (14 cabinets)
3 480V Load Centers-E1A,E1J,E1S (14 vertical divisions)
3 480V MCCs-E1A1,E1A2,E1A40 (24 vertical divisions)
13 Misc. Cabinets (e.g., auxiliary relay cabinets)
5 4160/480V Transformers-1A1,1A2,1J1,1J2,1S

SCENARIOS: Breaker fire, transformer fire, cable fire, bus fire, transient fire.

RELEVANT DATA:

Relative Fire Frequency Data (Reference 1)

Fire Type	Number	Note
Breaker	13	1
Transformer	5	2
Bus	3	3
Cable	2	4
Transient	1	5
TOTAL	24	

NOTES:
1. Events 14, 121, 123, 132, 141, 154, 159, 254, 268, 342, 357, 368, 382.
2. Events 193, 251, 363, 383, 394.
3. Events 235, 246, 256.
4. Events 8, 298.
5. Events 309, 310, 311, 313, 315, and 316 all were small welding fires in the switchgear room during cold shutdown at San Onofre 1. Inclusion in this database is conservative. (They are included as a single event because the fires are judged to be dependent.)

Room Geometry

Floor Area: 3,641 sq ft (Reference 2) [roughly 74 ft x 50 ft (Reference 3)]
Ceiling Height: 25 ft (next floor elevation is 35')
Lowest Cable Tray Height Above Floor: 9 ft (Reference 3)

Lowest Cable Tray Height Above Switchgear: 2 ft (Reference 4)
Cable Tray Width: 2 ft (Reference 3)
Typical Cable Tray Run Length: 60 ft
Maximum Cable Tray Run Length: 124 ft (room length + wid

Location of Key 4160V Breakers (Reference 5)

Equipment	Breaker Cubicle (Reference 6)
300 Ton Essential Chillers	4
ECW Pump	7
AFW Pump	8
CCW Pump	11

BREAKER FIRE:

(1) Roughly 13/24 switchgear room fires involve breakers (switchgear and MCC).
(2) Assume that there are 5 breaker cubicles per vertical division for the 480V Load Centers and MCCs. Therefore, there are

14 + 5*14 + 5*24 = 204

breaker cubicles in this zone.
(3) The conditional frequency of a breaker fire involving breaker X, given a fire in the switchgear room, is then

f(BKR) = f(fire in breaker X|fire in switchgear room)
= f(fire in any breaker|fire in switchgear room)
*f(fire in breaker X|fire in any breaker)
~ (13/24)*(1/204)
= 2.7E-03

TRANSFORMER FIRE:

(1) Roughly 5/24 switchgear room fires involve transformers.
(2) The conditional frequency of a fire in transformer X, given a fire in the switchgear room, is then

f(XFR) = f(fire in transformer X|fire in switchgear room)
= f(fire in any transformer|fire in switchgear room)
*f(fire in one transformer|fire in any transformer)
~ (5/24)*(1/5)
= 4.2E-02

RESPONSES TO STP PSA FIRE RISK QUESTIONS

BUS FIRE:

(1) Roughly 3/24 switchgear room fires involve busses.
(2) Assume that 1 bus is associated with each switchgear, load center, or MCC.
(3) The conditional frequency of a fire in bus X, given a fire in the switchgear room, is then

```
f(BUS)  = f(fire in bus X|fire in switchgear room)
        = f(fire in any bus|fire in switchgear room)
            *f(fire in bus X|fire in any bus)
        ~ (3/24)*(1/7)
        = 1.8E-02
```

CABLE FIRE:

(1) Roughly 2/24 switchgear room fires involve cables. Note that Event 8, which is one of the two fires in the database, involved thermal overload of cables and has since been remedied.
(2) From Reference 3, the total area of cable trays within a room appears to be greater than the floor area of the room itself.
(3) Conservatively assume that a critical set of cables has a run length of 124 ft (the maximum run length for a cable). The cable tray area is then

    2*124 = 248 sq ft

(4) The conditional frequency of a fire in cable tray X, given a fire in the switchgear room, is then

```
f(CAB)  = f(fire in cable tray X|fire in switchgear room)
        = f(fire in any cable tray|fire in switchgear
            room)
            *f(fire in cable tray X|fire in any cable tray)
        ~ (2/24)*(248/3641)
        = 5.7E-03
```

TRANSIENT FIRE:

(1) Conservatively assume that 1/24 switchgear room fires involve transient fuel.
(2) It is expected that most transient-fueled fires will be very small (e.g., involving small amounts of trash). Conservatively treat the small transient fires as 1-ft diameter oil fires.

(3) Conservatively assume that a critical set of cables has a run length of 124 ft (the maximum run length for a cable). The cable tray area is then

2*124 = 248 sq ft

(4) Although a 1-ft diameter oil fire can damage a cabinet, it must be fairly close to do this (Reference 7). The area fraction associated with this damage scenario is much smaller than that associated with cable tray damage.

(5) The Surry analysis (Reference 8) uses a modified version of COMPBRN III to predict that a 1-ft oil fire has to occur within 2 ft of a cable tray (horizontal distance) to cause damage. (Note that analyses treating uncertainty in the code and its inputs show that some small percentage of fires can cause damage at greater distances with some low probability.) It also shows that the 1-ft fire cannot cause damage to trays 10 ft above the floor. Conservatively assume that all 1-ft oil fires can damage the trays in this zone. The critical area is then

6*124 = 744 sq ft

(6) The Surry analysis (Reference 8) assumes that 70% of all transient-fueled fires are equivalent to 1-ft diameter oil fires. Seabrook (Reference 9) assumes a severity fraction of approximately 0.05 for the cable spreading room. This includes the reduction associated with transient fire occurrence - the equivalent fraction [0.05/(1/24)] would be greater than 1.0. The Indian Point Probabilistic Safety Study (IPPSS) values appear to be consistent with Seabrook (although IPPSS also includes area fractions). Use the Surry value (although it is believed to be strongly conservative).

(7) The conditional frequency of the loss of cable tray X due to a transient-fueled fire, given a fire in the switchgear room, is then

f(TRN) = f(loss of cable tray X due to transient fire| fire in switchgear room)
= f(transient fire|fire in switchgear room)
*f(transient fire equivalent to 1' oil fire| transient fire)
*f(transient fire damages cable tray X| 1' oil fire)
~ (1/24)*(0.70)*(744/3641)
= 6.0E-03

OTHER ASSUMPTIONS:

(1) Power to a 4160V load passes through: the 4160V bus and a 4160V breaker.

(2) Power to a load powered from an MCC in this room passes through: the 4160V bus, a 4160V breaker, a 4160/480V transformer, a 480V load center breaker, a 480V bus, a 480V load center breaker, an MCC "bus", and a 480V MCC contactor/breaker. Thus, a fire in any of 4 breakers, 3 buses, or 1 transformer can lead to loss of power to the load.

(3) The likelihood of power cable, bus, breaker, or transformer fires leading to hot shorts that energize 3-phase motors is negligible. Spurious motor actuation due to fire can be caused only by hot shorts in control cables.

(4) Only small fires are considered in this worksheet. It is assumed elsewhere in the fire analysis that 10% of all switchgear room fires are "large" and lead to loss of all equipment in the room. (This is believed to be conservative, since none of the 24 fires in the database have been that large.)

SCENARIO-SPECIFIC REDUCTION FACTORS:

(1) Scenario A, Sheet 1 (Reference 10):

(Open circuit in PORV control cable RCVS00655ACC) OR
(Hot short in block valve control cable RCVM0001ACC).

Conservatively assume that cables are in separate cable trays. Damage can be caused by a cable fire or a transient fire.

```
fRED(PORV) = 2*[f(CAB) + f(TRN)]
           = 2*(0.0057 + 0.0060)
           = 0.023
```

(2) Scenario B, Sheet 1 (Reference 10):

(Loss of power to AFW Pump A) OR
(Loss of power to AFW Pump A Ventilation Fan).

In terms of fire events:

[(Fire in 4160V bus) OR
(Fire in AFW Pump A Breaker) OR
(Open circuit in AFW Pump A power cable AFPMS0001-PC)] OR
[(Fire in 4160V bus) OR
(Fire in 4160V supply breaker to transformer) OR
(Fire in 4160/480V transformer) OR
(Fire in load center supply breaker from transformer) OR
(Fire in 480V load center bus) OR
(Fire in 480V load center supply breaker to MCC) OR
(Fire in 480V MCC bus) OR
(Fire in AFW Pump A Ventilation Fan motor contactor) OR
(Open circuit in Vent Fan power cable AFFN20001-PC) OR
(Open circuit in Vent Fan control cable AFFN20001-CC)]

Conservatively assume that all cables are in different trays.

```
fRED(AFW A) = 3*f(BUS) + 5*f(BKR) + f(XFR) + 3*[f(CAB)
              + f(TRN)]
            = 3*(0.018) + 5*(0.0027) + 0.042 + 3*(0.0057
              + 0.0060)
            = 0.15
```

(3) Scenario C, Sheet 1 (Reference 10):

(Hot short in PDP control cable CVPM00102ACC).

Damage can be caused by a cable fire or a transient fire.

fRED(PDP) = f(CAB) + f(TRN)
= 0.0057 + 0.0060
= 0.012

(4) Scenario A and B, Sheet 1 (Reference 10):

[(Open circuit in PORV control cable RCVS00655ACC) OR
(Hot short in block valve control cable RCVM0001ACC)]
AND
[(Loss of power to AFW Pump A) OR
(Loss of power to AFW Pump A Ventilation Fan)].

Damage can be caused only by cable or transient fires. 2 cables are involved in Scenario A, and 3 cables are involved in Scenario B. In the worst case, there are 2 trays carrying the critical cables. (Note that this assumption contradicts the assumption used in the analysis of Scenario B.)

fRED(AFW A,PORV) = 2*[f(CAB) + f(TRN)]
= 2*(0.0057 + 0.0060)
= 0.023

(5) Scenario A, Sheet 2 (Reference 10):

(Loss of power to ECW Pump A) OR
(Loss of power to ECW Pump A Ventilation Fans).

Note that the MCC for the ECW Pump A Ventilation Fans is outside of the switchgear room.

In terms of fire events:

[(Fire in 4160V bus) OR
(Fire in ECW Pump A Breaker) OR
(Open circuit in ECW Pump A power cable EWPM00101APC)
OR
(Open circuit in ECW Pump A control cable
EWPM00101ACC)]
OR
[(Fire in 4160V bus) OR (Fire in 4160V supply breaker
to transformer) OR
(Fire in 4160/480V transformer) OR

(Fire in load center supply breaker from transformer)
OR
(Fire in 480V load center bus) OR
(Fire in 480V load center supply breaker to MCC) OR
(Open circuit in ECW Pump A Ventilation Fans control cables EWFN20001-CC and EWFN20002-CC)]

Assume both fan cables are in the same tray. Assume other cables are in different trays.

fRED(ECW A) = 2*f(BUS) + 4*f(BKR) + f(XFR)
+ 3*[f(CAB) + f(TRN)]
= 2*(0.018) + 4*(0.0027) + 0.042
+ 3*(0.0057 + 0.0060)
= 0.12

(6) Scenario B, Sheet 2 (Reference 10):

(Loss of power to CCW Pump A) OR
(Loss of power to CCW Pump A Ventilation Fan).

In terms of fire events:
[(Fire in 4160V bus) OR
(Fire in CCW Pump A Breaker) OR
(Open circuit in CCW Pump A power cable CCPM00101APC)
OR
(Open circuit in CCW Pump A control cable CCPM00101ACC)] OR
[(Fire in 4160V bus) OR
(Fire in 4160V supply breaker to transformer) OR
(Fire in 4160/480V transformer) OR
(Fire in load center supply breaker from transformer)
OR
(Fire in 480V load center bus) OR
(Fire in 480V load center supply breaker to MCC) OR
(Fire in 480V MCC bus) OR
(Fire in CCW Pump A Ventilation Fan motor contactor)
OR
(Open circuit in Vent Fan power cable CCAHU0001-PC)
OR
(Open circuit in Vent Fan control cable CCAHU0001-CC)]

Conservatively assume that all cables are in different trays.

```
fRED(CCW A) = 3*f(BUS) + 5*f(BKR) + f(XFR) + 4*[f(CAB)
                + f(TRN)]
              = 3*(0.018) + 5*(0.0027) + 0.042
                + 4*(0.0057 +.0060)
              = 0.16
```

(7) Scenario C, Sheet 2 (Reference 10):

(Hot short in PDP control cable CVPM00102ACC).

Damage can be caused by a cable fire or a transient fire.

```
fRED(PDP) = f(CAB) + f(TRN)
          = 0.0057 + 0.0060
          = 0.012
```

(8) Scenario A and C, Sheet 2 (Reference 10):

[(Loss of power to ECW Pump A) OR
(Loss of power to ECW Pump A Ventilation Fans)]
AND
(Hot short in PDP control cable CVPM00102ACC).

Conservatively assume that the PDP control cable is in the same tray as one of the ECW cables listed in (5) above. Then

```
fRED(ECW A,PDP) = f(CAB) + f(TRN)
                = 0.0057 + 0.0060
                = 0.012
```

(9) Scenario B and C, Sheet 2 (Reference 10):

[(Loss of power to CCW Pump A) OR
(Loss of power to CCW Pump A Ventilation Fan)]
AND
(Hot short in PDP control cable CVPM00102ACC).

Conservatively assume that the PDP control cable is in the same tray as one of the CCW cables listed in (6) above. Then

```
fRED(CCW A,PDP) = f(CAB) + f(TRN)
                = 0.0057 + 0.0060
                = 0.012
```

SUMMARY OF REDUCTION FACTORS:

Scenario	Equipment	fRED
A, Sheet 1	PORV	0.023
B, Sheet 1	AFW A	0.15
C, Sheet 1	PDP	0.012
A and B, Sheet 1	AFW A, PORV	0.023
A, Sheet 2	ECW A	0.12
B, Sheet 2	CCW A	0.16
C, Sheet 2	PDP	0.012
A and C, Sheet 2	ECW A, PDP	0.012
B and C, Sheet 2	CCW A, PDP	0.012

REFERENCES:

(1) PLG, Inc., "Database for Probabilistic Risk Assessment of Light Water Nuclear Power Plants", PLG-0500, Volume 8, Fire Data, Revision 0, September 1990.

(2) STP PSA final report, Table 8.5-2.

(3) Electrical/Electrical Auxiliary Building Cable Tray Plan - Switchgear Room, Elevation 10'-0", Area 1F, Drawing 3-E-20-9-E-2819, Revision 13.

(4) Photographs of Zone Z004, R.P. Murphy, August 2, 1990.

(5) R.P. Murphy, c. August 27, 1990.

(6) Electrical/Electrical Auxiliary Building Equipment Arrangement Plan - Switchgear Room, Elevation 10'-0", Drawing 5-E-02-9-E-1853, Revision 11.

(7) Power Authority of the State of New York and Consolidated Edison Company of New York, Inc., "Indian Point Probabilistic Safety Study", Section 7.3, Fire Analysis, November 1981.

(8) "External Event Risk Analyses: Surry Power Station", NUREG/CR-4550, Volume 3, Revision 1, Part 3, prepared for the U.S. Nuclear Regulatory Commission by Sandia National Laboratories, September 1989, pages 5-19 and 5-20.

(9) PLG, Inc., "Seabrook Station Probabilistic Safety Assessment", PLG-0300, Section 9.4, Seabrook Fire Analysis, prepared for Public Service Company of New Hampshire and Yankee Atomic Electric Company, December 1983.

(10) J.W. Stetkar, Fire Analysis Reduction Factor Notes, Zone Z004, August 29, 1990.

RESPONSES TO STP PSA FIRE RISK QUESTIONS

REVIEW QUESTION 5

5. On page 9.3-4 of the PRA, the second level of fire screening is stated to be at a frequency of 2.0E-7/yr. In Table 9.3-9 of the PRA, 11 out of the 24 endstates are apparently screened using this criteria. While this criteria by itself has not completely eliminated the fire area given in the example, it did significantly contribute to its elimination in that approximately 50 percent of the endstates were screened. Provide the basis for the selection of 2.0E-7 as the screening criteria.

Response: The STP PSA fire scenario screening analyses were performed at a stage in the study when preliminary quantitative results were available from the analysis of all important internal initiating events and system failures. These preliminary results indicated with some confidence that the final mean core damage frequency from internal events would be in the range from 1.0E-04 per year to 3.0E-04 per year. The numerical criterion applied in the second and third levels of the screening analysis eliminated a fire scenario end state from further detailed consideration if its maximum possible contribution to the frequency of core damage was less than approximately one-tenth of one percent of the internal events total; i.e., less than approximately 2.0E-07 per year.

It should be noted that many of the fire scenarios that were eliminated by this criterion have actual core damage frequencies much lower than 2.0E-07 per year. In fact, of the 11 end states cited in STP PSA Table 9.3-9, only end state 20 was expanded to estimate its total contribution to core damage before it was eliminated by this criterion. The frequencies associated with the other 10 end states are the frequencies of plant impacts that fall far short of core damage; i.e., other independent system failures must occur before any of these 10 end states leads to core damage. The example for scenario Z004-FS-01 in the response to Question 4 shows that at this level of the screening analysis, the estimated core damage frequency from fire-induced failures typically retains considerably conservative assumptions and represents a maximum upper bound estimate to the actual total.

Section 2 of the STP PSA final report notes that the mean total core damage frequency from internal initiating events is approximately 1.7E-04 per year. This conclusion fully supports the use of 2.0E-07 as the original screening criterion in the second and third levels of the fire analysis.

REVIEW QUESTION 6

6. On page 9.3-4 of the PRA, endstates are quoted as being screened at 10 percent of the equivalent internal event frequency. Referring to the example given in Chapter 9 of the PRA, approximately one-third of the fire area endstates are screened by this (10 percent) criteria. It must be noted that typically much more chance for recovery exists for internal event failures as compared to fire-related failures. Therefore, the potential exists that if further development of the fire scenarios occurred their relative contribution with respect to similar internal events endstates might significantly be altered. Provide the rationale for the selection of the screening criteria of 10 percent.

Response: The STP PSA fire scenario screening analyses were performed at a stage in the study when preliminary quantitative results were available from the analysis of all important internal initiating events and system failures. Those analyses had already accounted for important operator recovery actions. For the internal event impacts most frequently used in the fire scenario screening process, the most important of these recovery actions are manual startup of the positive displacement charging pump, initiation of the smoke purge mode of EAB HVAC operation, and local efforts to restart the turbine-driven AFW pump after a spurious trip. With the exception of the diesel generator recovery model used in the analysis of loss of offsite power events, none of the other recovery analyses for the STP PSA take credit for repairs of failed equipment.

The 10% screening criterion for fire scenarios was applied to the total frequency of the comparable internal event impact, including consideration of the internal event recovery factors. Thus, the frequencies of nearly all the internal event impacts had already been reduced to account for reasonable recovery efforts before the fire scenarios were compared and screened using this criterion. Since no additional recovery actions were considered for the fire scenarios, the application of a numerical criterion of 10% ensured that the fire-induced contribution to each end state impact would remain a small fraction of the equivalent recovered internal event impact.

While it is certainly true that fires can present plant operators with confusing and stressful sets of stimuli, erroneous instrument readings, and unexpected equipment response, it should also be acknowledged that reasonable recovery actions are possible during many fire scenarios. The Browns Ferry fire demonstrated an extreme case of innovative and successful operator response. In a less severe fire that damages only a fraction of the plant systems, it certainly seems reasonable to account for relatively simple actions to start standby equipment, locally manipulate accessible components, and disconnect faulted control circuits.

It should be noted that the sensitivity analyses that were performed in response to review Question 1 used a much more conservative screening criterion of 1% of the equivalent recovered internal event impact. (The 1% criterion is also used in the example for fire scenario Z004-FS-01 in the response to Question 4.) Application of this criterion had no significant effect on the number of fire scenario end states eliminated at this level of the screening process, nor did it alter the overall conclusion from the fire analysis that fires are a very small contributor to the frequency of core damage at STP.

REVIEW QUESTION 7

7. In response to previous questions (HL&P letter ST-HL-AE-3414), the licensee stated that the total core damage frequency resulting from fire-initiated events is approximately 5.0E-7/year. On page 9.4-23 of the PRA, a simple summation of control room core damage frequency yields 8.02E-7/year. Explain this difference.

Response: The total contribution to STP core damage from fire-initiated events is approximately 5.06E-07 per year as stated in the referenced letter. This is approximately 0.3% of the total STP core damage frequency of 1.7E-04 per year. The responses in the referenced letter also provided details of the four most important control room fire sequences that dominate this total. Three of these sequences are initiated from fire scenario 18 in STP PSA Table 9.4-3, and the fourth sequence is initiated from fire scenario 23.

Table 9.4-3 presents the results from the control room fire scenario screening analysis. It is essentially equivalent to Table 9.3-9 for the analysis of MEAB fire scenario Z052-FS-01. (The same type of screening process was applied to the control room fire scenarios as is described for other plant fire zones in STP PSA final report Section 9.3. This process is also outlined in the example for fire scenario Z004-FS-01 in the response to Question 4.) A source of confusion has apparently been caused by the heading for the last column in Table 9.4-3. This column presents the total estimated core damage frequency that could result from each control room fire scenario. As noted on STP PSA final report page 9.4-19, this frequency was quantified "by using conservative values for the failure frequencies of components that have to fail independently of the fire for core damage to occur". Thus, the frequency values in the last column of Table 9.4-3 are simply consistent upper bound estimates that are used in the third level of screening for the control room fire scenarios. They are not precise estimates of the actual core damage frequencies that would result from formal propagation of each scenario through the event tree models.

As noted on STP PSA final report page 9.4-20, control room fire scenarios 10, 18, and 23 from Table 9.4-3 exceeded the 2.0E-07 per year numerical screening criterion and were subsequently quantified in the final plant model results. The sum of the actual core damage frequencies initiated from these three fire scenarios is the 5.06E-07 per year total cited in the previous response.

Appendix 6
September 1990 Review Question

ATTACHMENT 1
RESPONSES TO NRC QUESTIONS ON THE STP PSA FIRE RISK ANALYSIS

ADDITIONAL REVIEW QUESTION 1

1. **The licensee is requested to discuss the relevance of the Rancho Seco annunciator control panel fire on the STPEGS PSA. (SNL will provide information on the fire to the licensee.)**

Response: The referenced fire at Rancho Seco occurred in an annunciator control panel located in an auxiliary equipment room outside the main control room. This fire and two possibly related fires at Calvert Cliffs Unit 2 and Beaver Valley Unit 2 seem to have been caused by overheating of carbon resistors or other components on annunciator input circuit cards and were compounded by excessively high trip current ratings for the circuit breakers that protect these cards. The Calvert Cliffs and Beaver Valley fires also occurred in panels outside the main control room, and they were much smaller than the Rancho Seco fire. All three fires occurred in panels manufactured by Electro Devices, Inc. The South Texas plant does not contain any panels from this manufacturer.

Attachment 1.1 presents a sensitivity study that was performed to investigate the impact on the severity curve presented in STP PSA Figure 9.4-1 from adding the Rancho Seco fire to the panel fire event database. Two considerations indicate that the results from this sensitivity study may be quite conservative and inappropriate for use in a realistic fire analysis.

(1) By including only the Rancho Seco fire, the sensitivity study modifies the fire event database to inappropriately bias the population toward a higher conditional frequency of larger panel fires. The two smaller fires at Calvert Cliffs and Beaver Valley have not been included in this analysis, nor have any other panel fires that may have occurred since the PLG database was last updated in 1987. Since at least 8 of the 13 panel fires in the database are quite small, addition of a single larger fire without updating the database to include the full experience from all panel fires may significantly bias the results displayed by the panel fire severity curve.

(2) The Rancho Seco, Calvert Cliffs, and Beaver Valley fires may not be directly relevant to the analysis for South Texas. There is some evidence that these fires were all related to a design deficiency that may be unique to panels manufactured by Electro Devices, Inc. This assertion is supported by the fact that no similar fires have been reported in annunciator control panels from other manufacturers. It is not possible to completely dismiss these panel fires as irrelevant to South Texas

without more information about the fire causes and propagation modes, and more detailed information about the South Texas panel designs. However, evaluations performed by South Texas engineering personnel have concluded that these fires are isolated to a specific manufacturer's design and that no South Texas panel modifications are necessary in light of these events.

Figure 1-1 duplicates the panel fire severity curve from Figure 9.4-1 in the STP PSA final report and shows the results from the sensitivity study presented in Attachment 1.1. As noted in the study, the overall impact from including the Rancho Seco fire is quite small, increasing the combined geometry and severity factor for control room fire Scenario 6 by approximately 5%. When considered in the context of the database biases introduced by including only the Rancho Seco fire, this conclusion confirms that the original severity curve in Figure 9.4-1 quite reasonably represents the available data and may, in fact, be somewhat conservative.

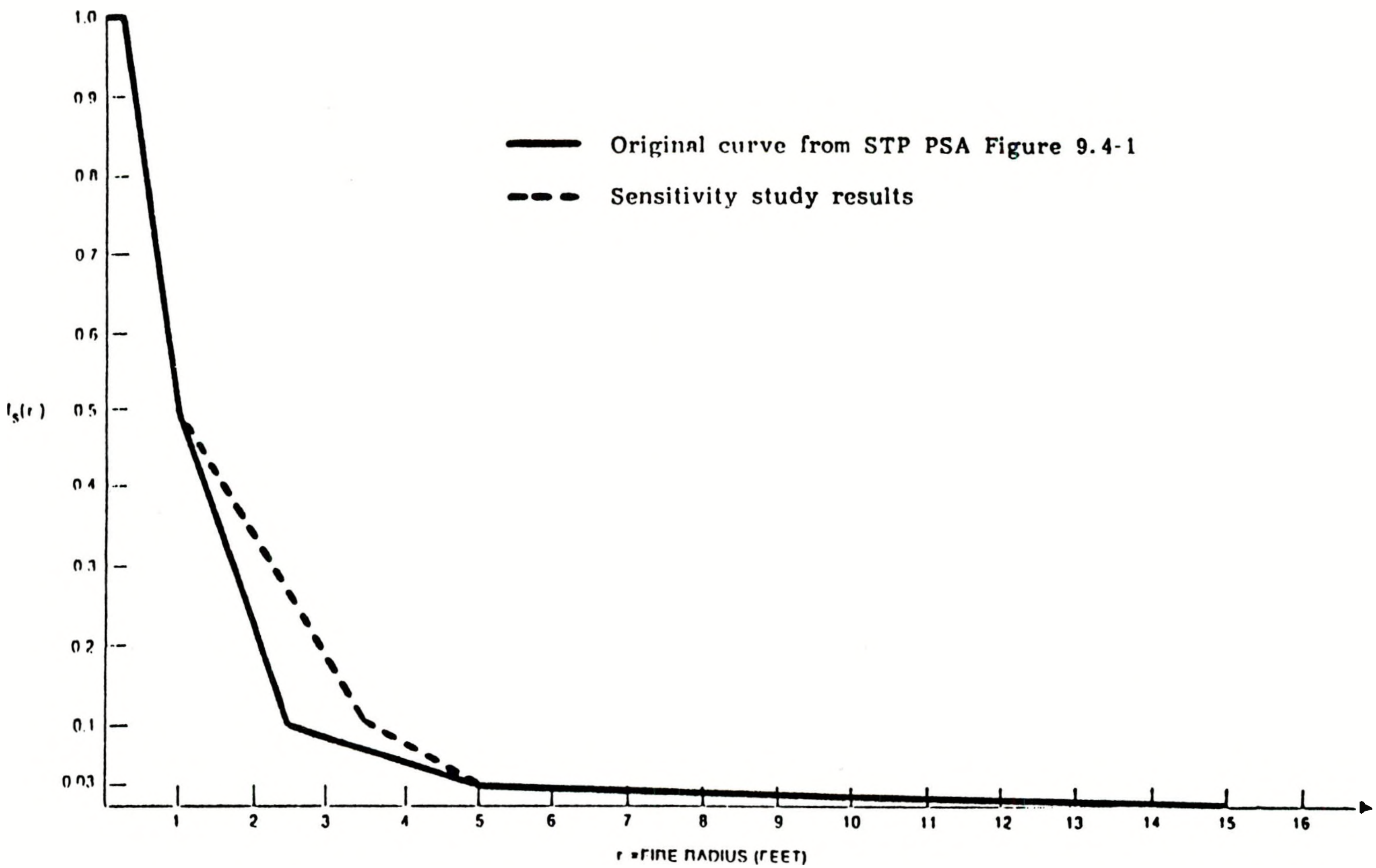

Figure 1-1. Comparison of Panel Fire Severity Factors from Original STP PSA Analysis and Rancho Seco Fire Sensitivity Study

ATTACHMENT 1.1

Rancho Seco Panel Fire Sensitivity Study

Zone: Main Control Room (Sensitivity Analysis Incorporating Rancho Seco Panel Fire)

Contents: Electrical Panels
Cable

Scenarios: Panel fire

Relevant Data:

Previous Analysis:

See Ref. 1. Figure 9.4-1 presents an assumed complementary cumulative distribution function for the damage radius associated with panel fires in the control room. This figure can be represented with the equations provided in Figure 9.4-1:

$$f_s = \begin{cases} 1 & 0.0 \leq r \leq 0.25 \text{ ft} \\ 1.167 - 0.667*r & 0.25 \leq r \leq 1.0 \text{ ft} \\ 0.767 - 0.267*r & 1.0 \leq r \leq 2.5 \text{ ft} \\ 0.017 - 0.03*r & 2.5 \leq r \leq 5.0 \text{ ft} \\ 0.045 - 0.003*r & 5.0 \leq r \leq 15.0 \text{ ft} \end{cases} \qquad (1)$$

Table 9.4-2, reproduced below in Table 1, applies this function towards the analysis of a single scenario (Scenario 6). (All units are in feet.)

Table 1 – Control Room Fire Scenario 6, Values for Δ_{ai} and f_{si}

Slice	Range	Radius	Area	f_s	f_s•Area
1	3–4	3.5	2.5	0.072	0.180
2	4–5	4.5	5.5	0.044	0.242
3	5–6	5.5	7	0.0285	0.200
4	6–7	6.5	11	0.0255	0.281
5	7–8	7.5	11.5	0.0225	0.259
6	8–9	8.5	15	0.0195	0.293
7,8,9	9–12	10.5	52.5	0.0135	0.709
10	12–13	12.5	16.5	0.0075	0.124
11	13–14	13.5	15.5	0.0045	0.0698
12	14–15	14.5	14.5	0.0015	0.0218
				Total	2.38

$$f_{g3} = \frac{1}{1350}\cdot 2.38 = 1.76\cdot 10^{-3}$$

Data from PLG Data Base [2]:

A review of panel fires incorporated in the PLG fire data base is discussed in Ref. 3. The review identifies 13 fires that are relevant, and provides damage radius estimates for 8 of the 13. (Information is too sketchy to provide estimates for the remaining 5.)

Table 11 of Ref. 3 is reproduced below in Table 2. It can be seen that *none* of the 8 fires is believed to have been very large. This is somewhat conservatively represented in Figure 9.4–1, which states that 50% of all panel fires have a damage radius of 1 ft or less, and 90% of all panel fires have a damage radius of 2.5 ft or less.

Table 2 – Electrical Panel/Relay Fires in PLG Fire Event Database [2]

ID	Location	Radius (ft)[1]	Radius (ft)[2]
156	CSR	0.25 ft	0.25 ft
166	Aux Bldg	0.50 ft	1.00 ft
169	Aux Bldg	< 0.10 ft	
188	Ctrl Bldg		
225	Ctrl Room	1.00 ft	
271	Other Bldg		
295		< 0.10 ft	
318	Other Bldg		
331	Ctrl Bldg		
336	Comp Room		
384	Rx Bldg	< 0.10 ft	
397	Ctrl Room	< 0.10 ft	
398	Ctrl Room	< 0.10 ft	

Notes:

1) Damage radius, estimated as part of the review in Ref. 3.
2) Damage radius, estimated in Ref. 4.

New Data (Not Included in Ref. 2):

Ref. 5 refers to 3 fires involving annunciator panels that occurred in early 1988:

Beaver Valley Unit 2 (January 28, 1988)
Calvert Cliffs Unit 2(February 1, 1988)
Rancho Seco (February 8, 1988)

All 3 involved panels produced by the same manufacturer.

According to Ref. 6, all 3 fires were extinguished within 10 minutes. It does not appear that any of the affected panels were in the main control rooms. In all cases, the annunciator system was disabled for a number of hours. Damage seems to have been more limited in the first 2 fires. In the Rancho Seco fire, 112 out of 192 circuit cards were damaged by heat, and 3 printed circuit boards were destroyed.

Conversations with an engineer at Rancho Seco indicates that the panel involved was 6–8 ft high, 4 ft wide, and 1 ft deep [7]. The damaged cards were distributed fairly uniformly throughout the panel. No thermal damage was observed outside of the panel, although there were smoke traces on the panel exterior. The panel is ventilated by louvers.

Sensitivity Analysis:

For the purposes of a sensitivity analysis, it is of interest to see how the results of Ref. 1 change if a single fire, comparable in severity to the Rancho Seco fire, is added to the data base.

Assume that 1 out of 9 fires has a damage radius of 3.5 ft[1]. Further assume that this fire can be represented by shifting a single point on the original curve for Figure 9.4–1: the point corresponding to $r = 2.5$ ft and $f_s = 0.10$ (roughly). Points lower on the curve need not be changed since most of the fires are still small, and points higher on the curve need not be changed since these correspond to very large fires that spread beyond the confines of the cabinet/panel.

The resulting modified fire severity curve is then:

$$f_s = \begin{cases} 1 & 0.0 \leq r \leq 0.25 \text{ ft} \\ 1.167 - 0.667 \cdot r & 0.25 \leq r \leq 1.0 \text{ ft} \\ 0.656 - 0.156 \cdot r & 1.0 \leq r \leq 3.5 \text{ ft} \\ 0.297 - 0.053 \cdot r & 3.5 \leq r \leq 5.0 \text{ ft} \\ 0.045 - 0.003 \cdot r & 5.0 \leq r \leq 15.0 \text{ ft} \end{cases} \tag{2}$$

The modified area and severity fractions are then as given in Table 3. Examination of Table 3 shows that the change in the reduction factor (i.e., the geometry–severity fraction f_{gs}) is very small, as only the first two slices (with the smallest corresponding panel areas) are affected. Larger changes in the reduction factor can be obtained only if it is shown that a larger fraction of panel fires can cause significant damage outside of the originating panel.

Conclusion:

The result of this sensitivity analysis is that incorporation of an event comparable to the Rancho Seco annunciator fire has a very small impact on the risk computed in Ref. 1 for a given scenario. Similar arguments can be made to show that the risk impact is small for all control room fire scenarios. Note that the impact of this event is expected to be even weaker when less conservative assumptions regarding the damage radius for that fire and the damage radii for the 5 neglected fires in Table 2 are made, and when the PLG fire event data base is properly updated to incorporate all panel fires that have occurred since the data base was last updated.

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[1]Note that this is conservative in three ways: a) it corresponds to a damage area of 38 ft^2, somewhat greater than the entire panel area, b) it neglects the fact that roughly 60% of the panel, rather than 100%, was damaged in the Rancho Seco fire, and c) it neglects the reasonable likelihood that the 5 events in Table 2 for which damage radii are not estimated actually were small.

Table 3 – Control Room Fire Scenario 6,
Sensitivity Analysis Values for Δ_{ai} and f_{si}

Slice	Range	Radius	Area	f_s	f_s*Area
1	3–4	3.5	2.5	0.11	0.275
2	4–5	4.5	5.5	0.059	0.266
3	5–6	5.5	7	0.0285	0.200
4	6–7	6.5	11	0.0255	0.281
5	7–8	7.5	11.5	0.0225	0.259
6	8–9	8.5	15	0.0195	0.293
7,8,9	9–12	10.5	52.5	0.0135	0.709
10	12–13	12.5	16.5	0.0075	0.124
11	13–14	13.5	15.5	0.0045	0.0698
12	14–15	14.5	14.5	0.0015	0.0218
				Total	2.50

$$f_{gs} = \frac{1}{1350} * 2.50 = 1.85 * 10^{-3}$$

4

References:

1) Pickard, Lowe and Garrick, Inc., "South Texas Project Probabilistic Safety Assessment," Draft Report Section 9, prepared for Houston Lighting and Power Company, 1989.
2) PLG Inc., "Database for Probabilistic Risk Assessment of Light Water Nuclear Power Plants," PLG-0500, Volume 8, Fire Data, Revision 0, September 1990.
3) N. Siu, "Damage Fractions and Related Issues in Fire Risk Analysis: Discussion and Applications to South Texas," prepared for PLG, Inc., September 1990.
4) K.N. Fleming, W.T. Houghton, and F.P. Scaletta, "A Methodology for Risk Assessment of Major Fires and Its Application to an HTGR Plant," GA-A15402, GA Technologies, Inc., 1979.
5) S. Newberry, Chief, Instrumentation and Control Systems Branch, Division of Engineering and Systems Technology, USNRC, Memorandum to W. Lanning, Chief, Events Assessment Branch, Division of Engineering and Systems Technology, USNRC, December 20, 1988.
6) Viewgraphs on Annunciator Cabinet Fires, 1988. (Included in same package as Ref. 4, transmitted from R. Murphy to N. Siu, October 4, 1990.)
7) Telephone conversation with J. Delezinski, Sacramento Municipal Utility District, October 5, 1990.

ATTACHMENT 1
RESPONSES TO NRC QUESTIONS ON THE STP
PSA FIRE RISK ANALYSIS

ADDITIONAL REVIEW QUESTION 2

2. The licensee is requested to assess the contribution to core damage frequency from fires originating in the control room cabinets which were previously screened from the analysis.

Response: The STP PSA control room fire analysis examined the core damage contribution from panel fires that could disable one or more of the components included in the plant event tree models. Other control room fires in panels that do not contain any equipment modeled in the PSA were screened from explicit evaluation. Concerns have been raised about possible human errors that may lead to core damage if the operators are forced to abandon the control room during any of these fires. The following observations conclude that these fire scenarios are not significant contributors to the frequency of core damage.

Frequency of Control Room Abandonment

The Surry PRA (Ref. 1) analyzes large control room fires that can lead to control room abandonment. The analysis focuses on fires in Benchboard 1-1. It is assumed that 10% of all fires involving this benchboard lead to control room abandonment. The Limerick PRA (Ref. 2) assumes that 1/40 (i.e., 2.5%) of control room cabinet fires propagate beyond the walls of the cabinet and that abandonment follows. The Diablo Canyon PRA (Ref. 3) assumes that 95% of all fires will be extinguished before evacuation is required.

None of the 13 panel fires in the PLG fire event database (Ref. 4, listed in Appendix C of Ref. 5) are described as having generated much smoke. This is probably because most, if not all, were small fires with a damage radius of less than 1 foot. It may also be due to a possible lack of sensitivity towards smoke issues on the part of the reporters. The recent Vandellos turbine building fire in Spain did generate a large amount of smoke that entered the control room. However, reports of that event do not indicate that the control room was abandoned.

On the basis of the information cited above, it seems that the assumption used in the Diablo Canyon analysis (i.e., that 5% of all control room fires will require abandonment) is reasonable for scoping studies. It is suspected that even this 5% value may be conservative, but this cannot be proven without more detailed modeling and/or more extensive fire event data.

The total frequency of control room fires used in the STP PSA is approximately 4.9E-03 fire per year. If 5% of these fires require abandonment, the estimated frequency of fire-induced control room abandonment is approximately 2.45E-04 event per year.

ATTACHMENT 1
RESPONSES TO NRC QUESTIONS ON THE STP
PSA FIRE RISK ANALYSIS

Background for Quantifying Operator Error Rates

Current state-of-the-art human reliability analyses do not generally address severe, unspecified errors of commission that may lead to core damage. Analyses are typically performed in the context of directed mission activities. The operators must complete a specific desired action in response to a defined set of equipment failures or procedural instructions. Failure to complete the action results in a known plant condition as defined by the PRA event sequence logic model. If combinations of automatic equipment responses and directed operator actions bring the plant to a stable shutdown condition, the analysis is considered complete, and the PRA concludes that no core damage will occur.

To establish the proper context for addressing the issue of control room abandonment, it should be noted that current PRAs do not quantify the core damage frequency that may result from operator errors of commission while they remain in the control room. Although a large number of relatively routine actions must be performed to maintain the plant in a stable shutdown condition, none of these actions are typically modeled or quantified as potential core damage contributors. This approach is reasonable. In these "success paths" through the PRA event model, the plant has been placed in a stable condition of core subcriticality, decay heat removal, and coolant inventory control. The operators must continue to monitor the running systems and provide relatively routine manual control functions such as adjusting cooldown rates, aligning makeup water supplies, controlling pressure, etc. If the operators make an error during a specific activity, there is generally a large amount of time available for the error to be discovered and corrected. If the error damages a specific piece of equipment, redundant alternatives are usually available to provide the same function.

It is generally agreed among PRA analysts that these conditions represent a "negligibly small" contribution to the frequency of core damage. However, it is extremely difficult, and beyond the state of the art in current human reliability analysis methods, to estimate how small this contribution might be. The entire nuclear power industry has accumulated experience from a very large number of reactor trips and other forced plant shutdowns. No event has led to core damage without a preceding series of equipment failures. In other words, there is no evidence that plant operators have ever been involved in a series of errors of commission that was so severe as to result in core damage. (The Chernobyl accident may refute this claim, but the pre-accident testing conditions at Chernobyl are certainly not typical of stable plant response.) This evidence supports the assertion that the "fatal" control room operator error rate must be less than approximately 1.0E-04 error per shutdown.

Recent U.S. nuclear power plant operating experience shows a typical forced shutdown rate of approximately 5 events per reactor year. Modern PRA results typically display individual core damage event sequences with frequencies in the range of 1.0E-08 per year or lower. Quantitative screening cutoff values are typically set at least two orders of magnitude below the displayed frequencies. These results infer that the assigned error rates for severe errors of commission must be much less than 1.0E-08 error per shutdown. Otherwise, the PRA results would display core damage sequences that contain no other failures except the initiating event and the unspecified "fatal" error.

The preceding discussion is not presented as justification for a specific human error rate for these unspecified errors of commission. It simply provides a "semi-quantitative" context for error rates that may be inferred from published PRA results. Modeling and quantification of these errors is, in fact, beyond the state of the art in current PRA methods and is an interesting topic for fundamental human reliability research. Omission of these errors from PRA models does not reduce the credibility of the quantitative results, and it does not detract from the ultimate goal of developing plant-specific insights for risk reduction and risk management. The methods, models, and data necessary to address these errors are essentially a generic issue related to the ultimate limits of human reliability, which apply equally to all plants, regardless of their specific designs, personnel, training, and procedures.

<u>Conditional Frequency of Core Damage After Control Room Abandonment</u>

The South Texas operators have three major tasks to accomplish when they abandon the control room.

(1) Trip the reactor if it has not already been shut down. This can be accomplished from the control room as the operators are leaving or from a number of remote locations throughout the plant.

(2) Transfer control to the auxiliary shutdown panels. This is accomplished at the transfer switch panels located in each essential switchgear room and at the auxiliary shutdown panels.

(3) Monitor and control operation of the systems required to maintain stable hot shutdown conditions. These actions are essentially the same as those performed from the main control room, using the controls at the auxiliary shutdown panels and local equipment control stations.

ATTACHMENT 1
RESPONSES TO NRC QUESTIONS ON THE STP
PSA FIRE RISK ANALYSIS

The STP PSA fire analysis results quantify the impact from control room panel fires that disable equipment required to maintain stable hot shutdown conditions. Therefore, the remaining fires that require control room abandonment have the full complement of mitigation systems available. Operator errors that lead to core damage under these conditions are analogous to the unspecified control room errors of commission discussed above.

All licensed operators at South Texas receive training on controlling the plant from the auxiliary shutdown panels. The plant emergency operating procedures contain instructions for all required actions after the decision is made to abandon the control room. The ability to transfer control to the auxiliary shutdown panels and subsequently maintain stable hot shutdown conditions was demonstrated during the plant startup testing program. However, it seems reasonable to expect that the operator error rate may be higher under these less familiar conditions of controlling plant operation from the auxiliary shutdown panels, compared with error rates in the main control room.

The preceding calculation indicates that the frequency of control room abandonment from all control room fires is approximately 2.45E-04 event per year. Table 7.6-1 in the STP PSA final report shows that the total frequency of plant trips from all causes other than fires is approximately 4.5 events per year. Since the total core damage frequency is approximately 1.7E-04 event per year, it is apparent that nearly all of these plant trips culminate in the desired condition of stable plant shutdown.

As noted above, control room errors of commission are judged to be negligibly small contributors to the frequency of core damage. It is not possible to provide reasonable absolute estimates for either of these error rates. However, it is possible to infer how much higher the error rate from the auxiliary shutdown panels would have to be, if these errors were to have the same core damage impact as the control room errors. The ratio of these error rates is given by the following equation.

Error Rate Ratio = (Frequency of non-fire events)/
(Frequency of control room abandonment)
= (4.5)/(2.45E-04)
= 1.84E+04

Therefore, in order for the fire-induced control room abandonment scenarios to have the same (negligibly small) contribution to core damage as the control room error scenarios, the operator error rate for controlling the plant from the auxiliary shutdown panels must be approximately 18,000 times higher than the control room error rate. This seems quite unlikely, based on the available procedures, training, and equipment to control the plant.

As a final comment, it should also be noted that the operators are not expected to remain outside the control room for an extended period of time. The available panel fire experience data indicate that the majority of control room fires are expected to be quite small and quickly extinguished. The operators may have to abandon the control room for a small fraction of these fires because of concerns about remaining in a smoky environment or the inconvenience of operating in supplied breathing apparatus. When the fire is extinguished and the room is ventilated, the operators may reoccupy the control room and resume their more familiar operating stations. Thus, it is expected that most of the activities performed from the auxiliary shutdown panels will involve monitoring and maintenance of essentially steady-state heat removal and inventory control functions with only minor adjustments to flows, levels, pressures, etc. More active changes in plant status, such as preparation for cooldown to cold shutdown, will be delayed until the control room is habitable.

References

1. "External Event Risk Analyses: Surry Power Station", NUREG/CR-4550, Volume 3, Revision 1, Part 3, prepared for the U.S. Nuclear Regulatory Commission by Sandia National Laboratories, September 1989.

2. NUS Corp., "Severe Accident Risk Assessment: Limerick Generating Station", prepared for Philadelphia Electric Co., Report No. 4161, April 1983.

3. Pacific Gas and Electric Co., "Final Report of the Diablo Canyon Long Term Seismic Program", Chapter 6, Probabilistic Risk Analysis, July 1988; PLG, Inc., "Diablo Canyon Probabilistic Risk Assessment", PLG-0637, Appendix F.3, Diablo Canyon Fire Risk Assessment, draft report, August 1988.

4. PLG, Inc., "Database for Probabilistic Risk Assessment of Light Water Nuclear Power Plants", PLG-0500, Volume 8, Fire Data, Revision 0, September 1990.

5. N.O. Siu, "Damage Fractions and Related Issues in Fire Risk Analysis: Discussion and Applications to South Texas", prepared for PLG, Inc., September 1990.

ATTACHMENT 1
RESPONSES TO NRC QUESTIONS ON THE STP
PSA FIRE RISK ANALYSIS

ADDITIONAL REVIEW QUESTION 3

3. The licensee is requested to assess the contribution to core damage frequency from fires in the turbine building which could fail offsite power.

Response: A conservative estimate for the frequency of turbine building fires that may cause a nonrecoverable loss of offsite power shows that these fires are insignificant compared with the frequency of unrecovered offsite power failures from other causes that are explicitly included in the STP PSA results.

3.1. Description of Turbine Building Fire Scenarios

The relevant components and cables that affect the availability of offsite power for the essential switchgear buses are listed below.

(1) 13.8 kV power cables from the Unit Auxiliary Transformer to the 13.8 kV switchgear buses.

(2) 13.8 kV power cables from the Standby Transformer to the 13.8 kV switchgear buses.

(3) 125 V DC normal control power cables to the 13.8 kV switchgear buses.

(4) 125 V DC alternate control power cables to the 13.8 kV switchgear buses.

(5) 13.8 kV switchgear buses F, G, and H.

3.1.1. Fires That May Damage the 13.8 kV AC Power Cables

The power supplies from the Unit Auxiliary Transformer are routed in a non-segregated bus duct that enters the northwest corner of the Turbine Building at Elevation 29'-0" and then enters the west side of the 13.8 kV Switchgear Room. The power supplies from the Standby Transformer are routed in underground conduits that enter the northeast corner of the Turbine Building and then enter each supply cabinet in the 13.8 kV Switchgear Room through the floor. Loss of offsite power to any of the 13.8 kV buses requires failure of power from both the Unit Auxiliary Transformer and the Standby

Transformer. Except for fires in the 13.8 kV Switchgear Room, no credible Turbine Building fires could be identified that would damage both of these supplies.

3.1.2. Fires That May Damage the 125 V DC Control Power Cables

Open circuits in both 125 V DC control power supplies will not affect the availability of offsite power to the 13.8 kV switchgear unless one of the 13.8 kV AC power supplies is also interrupted. It is quite unlikely that short circuits in these control power cables could cause spurious operation of the 13.8 kV circuit breakers. Each 13.8 kV circuit breaker is equipped with a mechanical ratchet to charge the breaker operating springs and mechanical pushbutton releases that allow the operators to locally trip or close the circuit breaker if no control power is available. However, it is conservatively assumed for this screening analysis that any Turbine Building fire that damages both sets of control power cables will cause a loss of all offsite power supplies to the 13.8 kV buses.

Normal 125 V DC control power for operation of the 13.8 kV circuit breakers is supplied from a battery bus located at Elevation 29'-0" in the Turbine Building. Two sets of cables are routed from this battery bus to separate distribution panels in the 13.8 kV Switchgear Room. One distribution panel supplies control power for operation of the circuit breakers at 13.8 kV buses F and H, and the second panel supplies control power for 13.8 kV buses G and J. One set of control power cables is routed in cable trays, and the second set is run in conduit. The exact routing of these cables was not fully verified in the field. However, it is assumed for this analysis that both sets of cables are routed in a relatively direct path from the battery bus to the 13.8 kV Switchgear Room and that the cable trays and conduit are reasonably close to each other throughout most of this span.

Alternate 125 V DC control power for operation of the 13.8 kV circuit breakers is supplied from a battery bus located at Elevation 10'-0" in the Electrical Auxiliary Building. The cables from this bus are routed in conduit along the eastern wall of the Turbine Building at Elevation 29'-0". Until the cables enter the 13.8 kV Switchgear Room, the separation distance between the first two sets of cables (from the Turbine Building battery bus) and the third set of cables (from the Electrical Auxiliary Building battery bus) is at least 20 feet.

Due to the large separation distance between these cables and the fact that two sets of cables are run in conduit, only an extremely large fire could be expected to cause damage to both control power supplies. Very large Turbine Building fires have occurred in nuclear power plants outside the United States (e.g., at the Muehleberg plant in Switzerland, the Maanshan plant in Taiwan, and the Vandellos plant in Spain). All of these fires had their origins at the main turbine generator. The available data do not indicate that any fires of comparable magnitude have occurred at nuclear power plants in the United States.

Examination of the equipment layout in the South Texas Turbine Building shows that fires located on the turbine floor at Elevation 79'-0" are unlikely to damage equipment at Elevation 29'-0" unless burning oil from these fires reaches the lower floors. The burning oil from a large turbine fire is most likely to fall into the condenser hotwell area. The farthest cable of interest is routed in conduit more than 100 feet away along the eastern wall of the Turbine Building. Therefore, the postulated oil pool fire at Elevation 29'-0" must be extremely large to damage this cable. It appears unlikely that any of the turbine fires experienced to date (including those in foreign nuclear power plants) caused thermal damage this far away from the fire source. (The Muehleberg fire did cause smoke damage throughout much of the Turbine Building, creating a long-term cleanup problem, but thermal damage was confined to the immediate vicinity of the fire.) However, further investigation regarding the exact damage radii for the Muehleberg, Maanshan, and Vandellos fires is required before the possibility of huge turbine oil fires can be summarily rejected as being of completely negligible frequency. Therefore, this screening analysis examines the likelihood that an extremely large Turbine Building fire damages all three sets of DC control power cables and causes an assumed loss of power at the 13.8 kV switchgear.

3.1.3. Fires That May Damage the 13.8 kV Switchgear

A large fire in the 13.8 kV Switchgear Room may damage the three 13.8 kV buses (i.e., buses F, G, and H) that supply normal offsite power to the essential AC power buses located in the Electrical Auxiliary Building. The following data summarize the geometry of this room.

Floor: 137 ft. long x 48 ft. wide = 6576 sq. ft. (Ref. 1)
Floor Elevation: 31 ft. (Ref. 1)
Ceiling Height: ~24 ft. (next zone at Elevation 55'-0")
Cabinet Separation (different divisions): >8 ft. (Ref. 1)
Cable Tray Width: 2 ft. (Ref. 2,3)
Typical Cable Run Length: 137 ft. (Ref. 2,3)

3.2. Availability of Emergency Offsite Power

None of the fires described in Section 3.1 will cause a complete loss of offsite power to all three essential AC power divisions. An additional offsite power supply is available from an independent 138 kV transmission circuit (the Blessing line) that connects to the Emergency Transformer in the South Texas Project switchyard. The 13.8 kV power supply cables from this transformer are routed in underground conduits directly from the switchyard to the Emergency Bus (i.e., 13.8 kV bus L) located in the Electrical Auxiliary Building. Therefore, this emergency offsite power supply cannot be damaged by any fires that occur in the Turbine Building.

If the normal 13.8 kV power supplies from the Unit Auxiliary Transformer and the Standby Transformer are deenergized, the operators can reenergize at least one of the essential buses from the main control room by simply closing the emergency offsite power supply breaker to the selected bus. Control power for operation of the emergency supply breakers is provided from the 125 V DC battery bus at Elevation 10'-0" in the Electrical Auxiliary Building. The emergency offsite power circuit has sufficient capacity to supply all loads from at least one essential AC power division. If the operators shed selected loads, more than one essential division may be reenergized from this supply.

3.3. Screening Analysis for Turbine Building Fire Frequencies

Table 3-1 lists 23 fires included in a Turbine Building fire frequency analysis documented in Reference 4. (The data are obtained from Reference 5.) The 23 events break down as follows.

Type	Fuel	Severity(1)	Events
Pump	Oil	Small	52, 341, 355, 378
Pump	Unknown	Unknown	283
Turbine-Generator	Oil, H-2	Small	69, 152, 199, 267, 345, 375, 377
Turbine-Generator	Oil, H-2	Moderate	107, 153, 299, 337, 376
Oil Line	Oil	Large(2)	255
Cable	Insulation	Small	240, 264
Other	See Notes	See Notes	87(3), 189(4), 366(5)

Notes:

(1) Based on narratives; "small" fires lead to minor, localized damage; "moderate" fires lead to widespread damage on burning component and have some potential to damage other components; "large" fires have strong potential to damage other components.

(2) Assumed, based on type of fire (ruptured oil line) and presence of offsite fire department.

(3) Small transient-fueled fire.

(4) Auxiliary boiler fire; no specifics on size or damage caused.

(5) Large outdoor transformer; caused damage to metal siding of Turbine Building; started fires within the building.

Although one event listed in Reference 4 (Event 20) is actually not a Turbine Building fire, the computed fire frequencies from that reference are conservatively used for this analysis. The mean Turbine Building fire frequency from Reference 4 is 0.047 fire per year during plant power operation.

3.3.1. Large Turbine Building Fires

Of the 23 Turbine Building fires listed in Table 3-1, 13 involved the main turbine-generator (including Event 255, which appears to be related). Thus, the fraction of Turbine Building fires in this category is approximately:

F(tg) = F(Turbine-generator fire | Fire in Turbine Building)

$\approx$ 13/23

= 0.57

Large turbine-generator fires have occurred in at least three foreign nuclear power plants (e.g., at Muehleberg, Maanshan, and Vandellos). A review of the available data indicates that no comparably-sized fires seem to have occurred at nuclear power plants in the United States, although Event 255 appears to have been a relatively large fire.

Due to the intervening floor at Elevation 55'-0", fires on the turbine deck at Elevation 79'-0" are very unlikely to cause damage to the 125 V DC cables at Elevation 29'-0". The experience data indicate that hydrogen fires away from the main generator are unlikely. Extremely large hydrogen fires, away from the main generator, that are capable of damaging equipment more than 100 feet away from the fire source are even less likely. However, it seems possible that burning oil from a large turbine oil fire could flow from the upper floor areas to Elevation 29'-0" in the vicinity of the main condenser hotwell. The available descriptions for the foreign turbine-generator fires do not indicate the extent of damage from burning oil.

For the purpose of this screening calculation, it is conservatively assumed that Event 255 from Table 3-1 represents a fire that is large enough to damage both sets of cables from the Turbine Building battery bus and the cables from the Electrical Auxiliary Building battery bus in the conduit along the eastern wall of the Turbine Building. Using this extremely conservative assumption, the conditional frequency of large Turbine Building fires is approximately

F(tbl) = F(Large turbine-generator fire ¦ Fire in Turbine Building)

~ 1/23

= 0.043

No additional plant-specific fire severity or geometry reduction factors are applied to further reduce this frequency. Therefore, a conservative screening estimate for the frequency of large turbine-generator fires that may produce enough burning oil to damage all the control power cables at Elevation 29'-0" is:

f(tbl) = f(Fire in Turbine Building)*F(tbl)

= (0.047)*(0.043)

= 2.04E-03 fire per year

3.3.2. 13.8 kV Switchgear Room Fires

Reference 6 presents Auxiliary Building switchgear room fire frequencies that range from 1.28E-03 per year to 1.33E-03 per year. The zones involved (Z004, Z042, and Z052) have less floor area than the Turbine Building 13.8 kV Switchgear Room, and they house lower voltage switchgear. However, each Auxiliary Building switchgear room contains more circuit breakers (approximately 200 480V and 4160V breakers, versus approximately 60 13.8 kV circuit breakers for the Turbine Building switchgear room).

None of the 23 Turbine Building fires listed in Table 3-1 appear to have occurred within a switchgear room. A Bayesian estimate for the fraction of Turbine Building fires occurring within a switchgear room, based on a uniform prior distribution and 0 events in 23 trials, is

F(swg) = F(Fire in switchgear room ¦ Fire in Turbine Building)

~ 4.0E-02

It is noted that when this value is combined with the mean Turbine Building fire frequency from Reference 4 (0.047 fire per year), the estimated switchgear room fire frequency is 1.88E-03 fire per year, which is slightly higher than the values given in Reference 6 for Auxiliary Building switchgear room fire frequencies.

The different divisions of switchgear cabinets in the 13.8 kV Switchgear Room are widely separated. Thus, it will take quite a large fire to damage all three buses of concern (i.e., buses F, G, and H). As in the analysis for Zone Z004 discussed in Reference 7, it is assumed that 10% of all fires in the switchgear room lead to damage of all switchgear. (In the case of Auxiliary Building switchgear room fires, the actual experience data indicate that this assumption appears to be very conservative.)

F(swl) = F(Switchgear room fire damages all buses ¦ Fire in Turbine Building)

= F(Fire in switchgear room damages all buses ¦ Fire in switchgear room)*

F(Fire in switchgear room ¦ Fire in Turbine Building)

= (0.10)*(0.04)

= 4.0E-03

Therefore, the frequency of a nonrecoverable loss of offsite power caused by a large fire in the 13.8 kV Switchgear Room is

f(swl) = f(Fire in Turbine Building)*F(swl)

= (0.047)*(4.0E-03)

= 1.88E-04 fire per year

3.4. Comparison with Equivalent Impact from Other Internal Events

A very conservative estimate for the total frequency of Turbine Building fires that may disable the normal offsite power supplies to the essential buses is given by the sum of the frequencies for large turbine-generator fires and large fires in the 13.8 kV Switchgear Room. It is assumed for this screening analysis that these fire-caused power failures are not recoverable during the time windows defined for the STP PSA electric power recovery models.

f(LOSP,fire) = f(tbl) + f(swl)
= (2.04E-03) + (1.88E-04)
= 2.23E-03 event per year

A quantitative screening evaluation was performed for these Turbine Building fires in the same manner as described for all other fire scenarios documented in the STP PSA final report.

3.4.1. First Level of Scenario Screening Evaluation

Table 7.6-1 from the STP PSA final report indicates that the loss of offsite power frequency used for this study is 1.29E-01 events per site calendar year. A nominal plant availability factor of 70% was applied to yield an initiating event frequency of 9.03E-02 loss of offsite power events per year during plant power operation.

A plant-specific offsite power recovery analysis for the South Texas Project site is documented in Section 15.6.3.1 of the STP PSA final report. All electric power recovery models applied in the final study results use a conservatively bounding available time window of 1 hour to restore power. (This time window is the most limiting time obtained from the combination of steam generator dryout, reactor coolant pump seal failure, and battery depletion described in Section 15.6.4 of the STP PSA final report.) Figure 15.6-1 shows that the mean conditional frequency for failure to recover offsite power within 1 hour at South Texas is approximately 0.45. (i.e., It is estimated that approximately 55% of the offsite power failures will be restored within 1 hour).

The frequency for unrecovered losses of offsite power that is used in the STP PSA final results is the product of these two values.

f(LOSP,int) = (9.03E-02 LOSP event per year)*

(0.45 failure to recover power within 1 hour)

= 4.06E-02 event per year

Thus, the frequency of unrecovered offsite power failures caused by Turbine Building fires (2.23E-03 event per year) is approximately 5.5% of the event frequency from other causes that are explicitly quantified in the STP PSA final results. This comparison fails to meet the first level of quantitative screening criteria used for other fire scenarios in the study (i.e., that the fire-induced event frequency is less than approximately 1% of the equivalent event frequency from "internal" causes).

3.4.2. Second Level of Scenario Screening Evaluation

The second level of fire event scenario screening examines the dominant additional system failures that must occur before these Turbine Building fires can cause core damage. These failures include combinations of the emergency diesel generators, essential cooling water trains, essential chilled water and Electrical Auxiliary Building HVAC trains, component cooling water trains, the turbine-driven auxiliary feedwater pump, the positive displacement charging pump, and the Technical Support Center diesel generator. The resulting equipment failure scenarios include credit for recovery of emergency diesel generator failures according to the models described in Section 15.6.3.2 of the STP PSA final report. The screening evaluation does not account for the relative timing of diesel generator failures, and the assigned recovery time window is 1 hour.

It is noted in Section 3.2 above that the emergency offsite power supply from the 138 kV Blessing line would be available to reenergize at least one of the essential buses during any Turbine Building fire event. The electric power recovery analyses documented in the STP PSA final report do not model this line as a fully independent power supply for offsite power failure events that are caused by external transmission grid or switchyard disturbances. However, the second level of quantitative screening for these Turbine Building fire scenarios conservatively models the emergency power supply from the Blessing line as a possible source of offsite power for one of the essential AC power divisions. A nominal unavailability of 0.10 is used for this power supply. It is believed that this estimate is a conservative upper bound for the actual unavailability of emergency offsite power, considering the combined effects from transmission line hardware failures, maintenance, and operator failures to close the emergency power supply circuit breaker within the available 1-hour time window.

Table 3-2 summarizes the dominant additional failures that must occur to cause core damage after loss of normal 13.8 kV power, and it provides estimates for the conditional frequency of each core damage scenario. These scenarios and the corresponding frequency estimates are derived from the event trees and the systems analyses documented in the STP PSA final report.

The results from the second level of scenario screening indicate that the total core damage frequency from all dominant event sequences initiated by a Turbine Building fire-induced loss of offsite power is approximately 3.0E-07 event per year. This is less than two-tenths of one percent (actually, 0.0017) of the total core damage frequency from all other events documented in the STP PSA final report (i.e., 1.7E-04 event per year).

3.5. Conclusions

The screening evaluations summarized in Section 3.4 indicate that Turbine Building fires that cause a loss of offsite power are inconsequential contributors to the frequency of core damage at STP. Several very conservative assumptions have been combined in these evaluations. The most important of these conservatisms are summarized below.

(1) It is assumed that failure of both 125 V DC control power supplies will cause a nonrecoverable loss of offsite power to the 13.8 kV switchgear. Open circuits in these control power cables will not cause circuit breakers to trip, and short circuits are quite unlikely to cause spurious circuit

breaker operations. No credit has been taken for possible operator actions to mechanically open and close the bus transfer circuit breakers in the 13.8 kV Switchgear Room after damage to the DC control power cables from a fire outside this room.

(2) Although three large turbine-generator fires have occurred at foreign nuclear power plants, the available data do not indicate that any comparably-sized fires have occurred at nuclear power plants in the United States. One event in the database appears to have involved the burning of a quantity of turbine hydraulic oil. This fire is used as direct evidence for the conditional frequency of turbine-generator fires that may produce large quantities of burning oil.

(3) It is assumed that a large turbine-generator fire will produce a sufficient amount of burning oil in a pool at Turbine Building Elevation 29'-0" to damage all three sets of 125 V DC control power cables. This damage includes the two Turbine Building battery supplies that are routed through Elevation 29'-0" (one in cable trays and one in conduit) and the Electrical Auxiliary Building battery supply that is routed in conduit along the eastern wall of the Turbine Building, more than 100 feet from the most likely location of a burning oil pool. No additional fire severity or geometry factors are applied to reduce the conditional frequency of damage to the Electrical Auxiliary Building battery cables.

(4) It is assumed that the emergency offsite power supply from the Blessing line can be used to reenergize one essential AC power division. A conservative value of 0.10 is assigned for the unavailability of this power supply, including operator failures to close the emergency supply breakers from the control room within 1 hour after the initial loss of normal 13.8 kV power.

(5) It is assumed that 10% of all fires that occur in the 13.8 kV Switchgear Room will be large enough to damage all three 13.8 kV buses F, G, and H.

It is believed that more detailed analyses of the initiating fire event frequency, the conditional frequency for loss of 13.8 kV power during a Turbine Building fire, and the conditional frequency of core damage after the loss of normal 13.8 kV power would show that these fires contribute substantially less to the total frequency of core damage than estimated from these conservative screening evaluations. Therefore, it is concluded that these Turbine Building fires are insignificant compared with the frequency of core damage from other causes of unrecovered losses of offsite power that are explicitly quantified in the STP PSA final results.

3.6. References

1. General Arrangement, Turbine Generator Building, Plan El. 29'-0", Area-A, Drawing 6G-01-9-M-0007, Revision 6.

2. Electrical, Turbine Generator Building Conduit Plan, Ground Floor El. 29'-0", Drawing 6-E-50-9-E-2230, Revision 9.

3. Electrical, Turbine Generator Building Conduit Plan, Ground Floor El. 29'-0", Drawing 6-E-50-9-E-2231, Revision 9.

4. Pickard, Lowe, and Garrick, Inc., "Analysis of Fire Frequency During Shutdown", prepared for Public Service Company of New Hampshire, PLG-0602, January 1988.

5. PLG, Inc., "Database for Probabilistic Risk Assessment of Light Water Nuclear Power Plants", PLG-0500, Volume 8, Fire Data, Revision 0, September 1990.

6. Pickard, Lowe, and Garrick, Inc., "South Texas Project Probabilistic Safety Assessment", Section 8, Table 8.5-2, prepared for Houston Lighting and Power Company, 1989.

7. N.O. Siu, "Damage Fractions and Related Issues in Fire Risk Analysis: Discussion and Applications to South Texas", prepared for PLG, Inc., September 1990.

Table 3-1. Turbine Building Fires (References 4 and 5)

Event	Description
52	Feedwater pump; oil-soaked insulation; hot pipe; portable extinguishers (30 minutes); small losses.
69	High pressure turbine; oil-soaked insulation; hot pipe.
87	Ping pong balls; smoking; sprinklers (15 minutes); small losses.
107	Turbine oil purifier system; leaking oil; heater; portable extinguishers (30 minutes); cables above fire charred; moderate losses.
152	Turbine generator; leaking hydrogen; spontaneous combustion; automatic CO_2 (<5 minutes); small losses.
153	Turbine generator; leaking hydrogen; spontaneous combustion; manual CO_2 (45 minutes); moderate losses.
189	Auxiliary boiler.
199	Turbine generator; hydrogen in bearings; spontaneous combustion; fire brigade, hose stream, manual CO_2 (35 minutes); minor water damage to electronics.
240	Cable tray fire; smoldering.
255	Ruptured hydraulic oil line; offsite fire department.
264	Cable tray fire; welding/cutting.
267	Generator pilot exciter unit.
283	Condensate booster pump.
299	Turbine generator; hydrogen leaked into exciter; fire brigade.
337	Turbine generator; hydrogen leak, explosion; automatic CO_2 (14 minutes).
341	Feedwater pump; oil-soaked insulation; fire brigade; minor fire.
345	Turbine generator; insulation.
355	Feedwater pump; overheated bearing; fire brigade (15 minutes); localized damage.
366	Auxiliary transformer; spread to turbine building after damaging metal siding; automatic deluge, fire brigade (15 minutes).
375	Turbine generator; leaking hydrogen; (30 seconds).
376	Turbine generator; leaking oil (immediately followed Event 375); fire brigade (30 minutes).
377	Generator brush assembly; automatic CO_2 (35 minutes).
378	Feedwater pump; fire brigade (15 minutes); localized damage.

NOTE: "Small loss" fires led to losses of less than $5,000; "moderate loss" fires led to losses between $5,000 and $50,000.

Table 3-2. Level 2 Screening: Evaluation of Dominant Additional Failures to Cause Core Damage from Turbine Building Fires that Disable All Normal 13.8 kV Power

Fire Event Frequency: 2.23E-03/yr

Additional Failures to Cause Core Damage:

1. DG A, DG B, DG C, Blessing, DG Recovery, (AFW D or PDP)
2. DG A, DG B, ECW C, Blessing, DG Recovery, (AFW D or PDP)
3. DG A, ECW B, DG C, Blessing, DG Recovery, (AFW D or PDP)
4. ECW A, DG B, DG C, Blessing, DG Recovery, (AFW D or PDP)
5. DG A, ECW B, ECW C, Blessing, DG Recovery, (AFW D or PDP)
6. ECW A, DG B, ECW C, Blessing, DG Recovery, (AFW D or PDP)
7. ECW A, ECW B, DG C, Blessing, DG Recovery, (AFW D or PDP)
8. ECW A, ECW B, ECW C, (AFW D or PDP)
9. DG A, DG B, ECH C, Blessing, DG Recovery, Smoke Purge, (AFW D or PDP)
10. DG A, DG B, Fan C, Blessing, DG Recovery, (AFW D or PDP)
11. DG A, ECH B, DG C, Blessing, DG Recovery, Smoke Purge, (AFW D or PDP)
12. DG A, Fan B, DG C, Blessing, DG Recovery, (AFW D or PDP)
13. ECH A, DG B, DG C, Blessing, DG Recovery, Smoke Purge, (AFW D or PDP)
14. Fan A, DG B, DG C, Blessing, DG Recovery, (AFW D or PDP)
15. DG A, ECH B, ECH C, Blessing, DG Recovery, Smoke Purge, (AFW D or PDP)
16. DG A, ECH B, Fan C, Blessing, DG Recovery, Smoke Purge, (AFW D or PDP)
17. DG A, Fan B, ECH C, Blessing, DG Recovery, Smoke Purge, (AFW D or PDP)
18. DG A, Fan B, Fan C, Blessing, DG Recovery, (AFW D or PDP)
19. ECH A, DG B, ECH C, Blessing, DG Recovery, Smoke Purge, (AFW D or PDP)
20. ECH A, DG B, Fan C, Blessing, DG Recovery, Smoke Purge, (AFW D or PDP)
21. Fan A, DG B, ECH C, Blessing, DG Recovery, Smoke Purge, (AFW D or PDP)
22. Fan A, DG B, Fan C, Blessing, DG Recovery, (AFW D or PDP)
23. ECH A, ECH B, DG C, Blessing, DG Recovery, Smoke Purge, (AFW D or PDP)
24. ECH A, Fan B, DG C, Blessing, DG Recovery, Smoke Purge, (AFW D or PDP)
25. Fan A, ECH B, DG C, Blessing, DG Recovery, Smoke Purge, (AFW D or PDP)
26. Fan A, Fan B, DG C, Blessing, DG Recovery, (AFW D or PDP)
27. ECH A, ECH B, ECH C, Smoke Purge, (AFW D or PDP)
28. ECH A, ECH B, Fan C, Smoke Purge, (AFW D or PDP)
29. ECH A, Fan B, ECH C, Smoke Purge, (AFW D or PDP)
30. Fan A, ECH B, ECH C, Smoke Purge, (AFW D or PDP)
31. ECH A, Fan B, Fan C, Smoke Purge, (AFW D or PDP)
32. Fan A, ECH B, Fan C, Smoke Purge, (AFW D or PDP)
33. Fan A, Fan B, ECH C, Smoke Purge, (AFW D or PDP)
34. Fan A, Fan B, Fan C, (AFW D or PDP)

Table 3-2. (Page 2 of 7) Level 2 Screening: Evaluation of Dominant Additional Failures to Cause Core Damage from Turbine Building Fires that Disable All Normal 13.8 kV Power

35. DG A, ECW B, ECH C, Blessing, DG Recovery, Smoke Purge, (AFW D or PDP)
36. DG A, ECW B, Fan C, Blessing, DG Recovery, Smoke Purge, (AFW D or PDP)
37. DG A, ECH B, ECW C, Blessing, DG Recovery, Smoke Purge, (AFW D or PDP)
38. DG A, Fan B, ECW C, Blessing, DG Recovery, (AFW D or PDP)
39. ECW A, DG B, ECH C, Blessing, DG Recovery, Smoke Purge, (AFW D or PDP)
40. ECW A, DG B, Fan C, Blessing, DG Recovery, Smoke Purge, (AFW D or PDP)
41. ECH A, DG B, ECW C, Blessing, DG Recovery, Smoke Purge, (AFW D or PDP)
42. Fan A, DG B, ECW C, Blessing, DG Recovery, (AFW D or PDP)
43. ECW A, ECH B, DG C, Blessing, DG Recovery, Smoke Purge, (AFW D or PDP)
44. ECW A, Fan B, DG C, Blessing, DG Recovery, Smoke Purge, (AFW D or PDP)
45. ECH A, ECW B, DG C, Blessing, DG Recovery, Smoke Purge, (AFW D or PDP)
46. Fan A, ECW B, DG C, Blessing, DG Recovery, (AFW D or PDP)
47. ECW A, ECW B, ECH C, Smoke Purge, (AFW D or PDP)
48. ECW A, ECW B, Fan C, (AFW D or PDP)
49. ECW A, ECH B, ECW C, Smoke Purge, (AFW D or PDP)
50. ECW A, Fan B, ECW C, (AFW D or PDP)
51. ECH A, ECW B, ECW C, Smoke Purge, (AFW D or PDP)
52. Fan A, ECW B, ECW C, (AFW D or PDP)
53. ECW A, ECH B, ECH C, Smoke Purge, (AFW D or PDP)
54. ECW A, ECH B, Fan C, Smoke Purge, (AFW D or PDP)
55. ECW A, Fan B, ECH C, Smoke Purge, (AFW D or PDP)
56. ECW A, Fan B, Fan C, (AFW D or PDP)
57. ECH A, ECW B, ECH C, Smoke Purge, (AFW D or PDP)
58. ECH A, ECW B, Fan C, Smoke Purge, (AFW D or PDP)
59. Fan A, ECW B, ECH C, Smoke Purge, (AFW D or PDP)
60. Fan A, ECW B, Fan C, (AFW D or PDP)
61. ECH A, ECH B, ECW C, Smoke Purge, (AFW D or PDP)
62. ECH A, Fan B, ECW C, Smoke Purge, (AFW D or PDP)
63. Fan A, ECH B, ECW C, Smoke Purge, (AFW D or PDP)
64. Fan A, Fan B, ECW C, (AFW D or PDP)
65. DG A, DG B, CCW C, Blessing, DG Recovery, PDP
66. DG A, CCW B, DG C, Blessing, DG Recovery, PDP
67. CCW A, DG B, DG C, Blessing, DG Recovery, PDP
68. DG A, CCW B, CCW C, Blessing, DG Recovery, PDP
69. CCW A, DG B, CCW C, Blessing, DG Recovery, PDP
70. CCW A, CCW B, DG C, Blessing, DG Recovery, PDP
71. CCW A, CCW B, CCW C, PDP
72. DG A, ECW B, CCW C, Blessing, DG Recovery, PDP
73. DG A, CCW B, ECW C, Blessing, DG Recovery, PDP

Table 3-2. (Page 3 of 7) Level 2 Screening: Evaluation of Dominant Additional Failures to Cause Core Damage from Turbine Building Fires that Disable All Normal 13.8 kV Power

74. ECW A, DG B, CCW C, Blessing, DG Recovery, PDP
75. CCW A, DG B, ECW C, Blessing, DG Recovery, PDP
76. ECW A, CCW B, DG C, Blessing, DG Recovery, PDP
77. CCW A, ECW B, DG C, Blessing, DG Recovery, PDP
78. ECW A, ECW B, CCW C, PDP
79. ECW A, CCW B, ECW C, PDP
80. CCW A, ECW B, ECW C, PDP
81. ECW A, CCW B, CCW C, PDP
82. CCW A, ECW B, CCW C, PDP
83. CCW A, CCW B, ECW C, PDP

Approximate Conditional Core Damage Frequency:

1. G3*(0.10)*(0.273)*(AFR' + PDJ)
   3.375E-05
2. G2*WCO*(0.10)*(0.273)*(AFR' + PDJ)
   1.356E-06
3. G2*WBE*(0.10)*(0.273)*(AFR' + PDJ)
   1.781E-05
4. G2*WAB*(0.10)*(0.273)*(AFR' + PDJ)
   7.464E-07
5. G1*W23*(0.10)*(0.348)*(AFR' + PDJ)
   1.752E-06
6. G1*W25*(0.10)*(0.348)*(AFR' + PDJ)
   1.609E-07
7. G1*W22*(0.10)*(0.348)*(AFR' + PDJ)
   8.549E-07
8. W32*(AFR' + PDJ)
   1.083E-05
9. G2*CLG*(0.10)*(0.273)*OS03*(AFR' + PDJ)
   3.289E-07
10. G2*FCM*(0.10)*(0.273)*(AFR' + PDJ)
    6.322E-06
11. G2*CLO*(0.10)*(0.273)*OS03*(AFR' + PDJ)
    1.822E-07
12. G2*FBG*(0.10)*(0.273)*(AFR' + PDJ)
    2.720E-07
13. G2*CLK*(0.10)*(0.273)*OS03*(AFR' + PDJ)
    1.822E-07
14. G2*FAB*(0.10)*(0.273)*(AFR' + PDJ)
    2.720E-07
15. G1*CLX*(0.10)*(0.348)*OS03*(AFR' + PDJ)
    7.545E-09
16. G1*CLO*FCM*(0.10)*(0.348)*OS03*(AFR' + PDJ)
    6.510E-08
17. G1*FBG*CLG*(0.10)*(0.348)*OS03*(AFR' + PDJ)
    5.056E-09

Table 3-2. (Page 4 of 7) Level 2 Screening: Evaluation of Dominant Additional Failures to Cause Core Damage from Turbine Building Fires that Disable All Normal 13.8 kV Power

18. G1*F25*(0.10)*(0.348)*(AFR' + PDJ)
1.178E-07
19. G1*CLW*(0.10)*(0.348)*OS03*(AFR' + PDJ)
2.103E-08
20. G1*CLK*FCM*(0.10)*(0.348)*OS03*(AFR' + PDJ)
6.510E-08
21. G1*FAB*CLG*(0.10)*(0.348)*OS03*(AFR' + PDJ)
5.056E-09
22. G1*F25*(0.10)*(0.348)*(AFR' + PDJ)
1.178E-07
23. G1*CLQ*(0.10)*(0.348)*OS03*(AFR' + PDJ)
2.924E-08
24. G1*CLK*FBG*(0.10)*(0.348)*OS03*(AFR' + PDJ)
2.801E-09
25. G1*FAB*CLO*(0.10)*(0.348)*OS03*(AFR' + PDJ)
2.801E-09
26. G1*F23*(0.10)*(0.348)*(AFR' + PDJ)
2.620E-08
27. CLP*OS03*(AFR' + PDJ)
2.545E-07
28. CLQ*FCM*OS03*(AFR' + PDJ)
3.203E-07
29. CLW*FBG*OS03*(AFR' + PDJ)
9.911E-09
30. CLX*FAB*OS03*(AFR' + PDJ)
3.556E-09
31. F25*CLK*OS03*(AFR' + PDJ)
3.720E-08
32. F25*CLO*OS03*(AFR' + PDJ)
3.720E-08
33. F23*CLG*OS03*(AFR' + PDJ)
1.493E-08
34. F33*(AFR' + PDJ)
8.239E-07
35. G1*WBE*CLG*(0.10)*(0.348)*OS03*(AFR' + PDJ)
3.311E-07
36. G1*WBE*FCM*(0.10)*(0.348)*(AFR' + PDJ)
6.364E-06
37. G1*CLO*WCO*(0.10)*(0.348)*OS03*(AFR' + PDJ)
1.397E-08
38. G1*FBG*WCO*(0.10)*(0.348)*(AFR' + PDJ)
2.085E-08
39. G1*WAB*CLG*(0.10)*(0.348)*OS03*(AFR' + PDJ)
1.388E-08
40. G1*WAB*FCM*(0.10)*(0.348)*(AFR' + PDJ)
2.667E-07
41. G1*CLK*WCO*(0.10)*(0.348)*OS03*(AFR' + PDJ)
1.397E-08

Table 3-2. (Page 5 of 7) Level 2 Screening: Evaluation of Dominant Additional Failures to Cause Core Damage from Turbine Building Fires that Disable All Normal 13.8 kV Power

42. G1*FAB*WCO*(0.10)*(0.348)*(AFR' + PDJ)
2.085E-08
43. G1*WAB*CLO*(0.10)*(0.348)*OS03*(AFR' + PDJ)
7.686E-09
44. G1*WAB*FBG*(0.10)*(0.348)*(AFR' + PDJ)
1.147E-08
45. G1*CLK*WBE*(0.10)*(0.348)*OS03*(AFR' + PDJ)
1.834E-07
46. G1*FAB*WBE*(0.10)*(0.348)*(AFR' + PDJ)
2.738E-07
47. W22*CLG*OS03*(AFR' + PDJ)
4.872E-07
48. W22*FCM*(AFR' + PDJ)
9.366E-06
49. W25*CLO*OS03*(AFR' + PDJ)
5.078E-08
50. W25*FBG*(AFR' + PDJ)
7.581E-08
51. W23*CLK*OS03*(AFR' + PDJ)
5.531E-07
52. W23*FAB*(AFR' + PDJ)
8.257E-07
53. WAB*CLX*OS03*(AFR' + PDJ)
9.759E-09
54. WAB*CLO*FCM*OS03*(AFR' + PDJ)
8.420E-08
55. WAB*FBG*CLG*OS03*(AFR' + PDJ)
6.539E-09
56. WAB*F25*(AFR' + PDJ)
1.524E-07
57. WBE*CLW*OS03*(AFR' + PDJ)
6.490E-07
58. WBE*CLK*FCM*OS03*(AFR' + PDJ)
2.009E-06
59. WBE*FAB*CLG*OS03*(AFR' + PDJ)
1.560E-07
60. WBE*F25*(AFR' + PDJ)
3.636E-06
61. WCO*CLQ*OS03*(AFR' + PDJ)
6.872E-08
62. WCO*CLK*FBG*OS03*(AFR' + PDJ)
6.583E-09
63. WCO*FAB*CLO*OS03*(AFR' + PDJ)
6.583E-09
64. WCO*F23*(AFR' + PDJ)
6.159E-08

Table 3-2. (Page 6 of 7) Level 2 Screening: Evaluation of Dominant Additional Failures to Cause Core Damage from Turbine Building Fires that Disable All Normal 13.8 kV Power

65. G2*KCO*(0.10)*(0.273)*PDJ
5.525E-07
66. G2*KBE*(0.10)*(0.273)*PDJ
1.096E-05
67. G2*KAB*(0.10)*(0.273)*PDJ
4.253E-07
68. G1*K23*(0.10)*(0.348)*PDJ
5.244E-07
69. G1*K25*(0.10)*(0.348)*PDJ
5.049E-08
70. G1*K22*(0.10)*(0.348)*PDJ
4.015E-07
71. K32*PDJ
2.801E-06
72. G1*WBE*KCO*(0.10)*(0.348)*PDJ
5.562E-07
73. G1*KBE*WCO*(0.10)*(0.348)*PDJ
8.407E-07
74. G1*WAB*KCO*(0.10)*(0.348)*PDJ
2.331E-08
75. G1*KAB*WCO*(0.10)*(0.348)*PDJ
3.261E-08
76. G1*WAB*KBE*(0.10)*(0.348)*PDJ
4.626E-07
77. G1*KAB*WBE*(0.10)*(0.348)*PDJ
4.281E-07
78. W22*KCO*PDJ
8.186E-07
79. W25*KBE*PDJ
3.056E-06
80. W23*KAB*PDJ
1.291E-06
81. WAB*K23*PDJ
6.782E-07
82. WBE*K25*PDJ
1.558E-06
83. WCO*K22*PDJ
9.437E-07

Approximate Total Core Damage Frequency: 2.87E-07/yr

Table 3-2. (Page 7 of 7) Level 2 Screening: Evaluation of Dominant Additional Failures to Cause Core Damage from Turbine Building Fires that Disable All Normal 13.8 kV Power

Split Fraction*	Description	Value
G1	Diesel Generator A (B) (C) Failure	1.178E-01
G2	Diesel Generators A and B (A and C) (B and C) Failure	1.887E-02
G3	Diesel Generators A, B, and C Failure	4.524E-03
WAB	ECW Train A Failure	5.302E-03
WBE	ECW Train B Failure	1.265E-01
WCO	ECW Train C Failure	9.636E-03
W22	ECW Trains A and B Failure	7.632E-04
W25	ECW Trains A and C Failure	1.436E-04
W23	ECW Trains B and C Failure	1.564E-03
W32	ECW Trains A, B, and C Failure	3.962E-05
CLK	ECH Train A Failure	2.609E-02
CLO	ECH Train B Failure	2.609E-02
CLG	ECH Train C Failure	4.710E-02
CLQ	ECH Trains A and B Failure	5.262E-04
CLW	ECH Trains A and C Failure	3.785E-04
CLX	ECH Trains B and C Failure	1.358E-04
CLP	ECH Trains A, B, and C Failure	1.878E-05
FAB	EAB HVAC Fan Train A Failure	1.932E-03
FBG	EAB HVAC Fan Train B Failure	1.932E-03
FCM	EAB HVAC Fan Train C Failure	4.491E-02
F23	EAB HVAC Fan Trains A and B Failure	2.339E-05
F25	EAB HVAC Fan Trains A and C (B and C) Failure	1.052E-04
F33	EAB HVAC Fan Trains A, B, and C Failure	3.015E-06
KAB	CCW Train A Failure	4.236E-03
KBE	CCW Train B Failure	1.092E-01
KCO	CCW Train C Failure	5.503E-03
K22	CCW Trains A and B Failure	5.025E-04
K25	CCW Trains A and C Failure	6.319E-05
K23	CCW Trains B and C Failure	6.563E-04
K32	CCW Trains A, B, and C Failure	1.437E-05
AFR'	AFW Train D Failure (After Turbine Recovery)	7.836E-02
PDJ	PDP Failure (Including TSC Diesel)	1.949E-01
OS03	Operator Failure to Start Smoke Purge	4.960E-02

*NOTE: System failure split fractions are documented in STP PSA Appendix F. Operator action split fractions are documented in STP PSA Table 15.4-53. Diesel generator recovery factors are from STP PSA Table 15.6-2 with offsite power not recoverable. Total unavailability of emergency offsite power from the Blessing line is assumed to be 0.10 for this analysis.

FIRE-RELATED QUESTIONS

Question 1

Provide the basis for using the fire occurrence frequency for auxiliary buildings for the analysis of the STP cable spreading rooms instead of the frequency of fires in cable spreading rooms used in previous PRAs.

Response

Five of the fire zones in the STP PSA fire risk screening analysis are typical of cable spreading rooms in other plants. These zones are Z010, Z026, Z047, Z057, and Z060. All of these zones are located in the mechanical and electrical auxiliary building (MEAB). Other zones in the MEAB are also predominantly populated by cable trays. However, these other zones include corridors, cable vaults, and cable penetration rooms that are similar to areas found in other plant auxiliary buildings. It seems reasonable to include these other areas in the population of fire zones allocated to the "auxiliary building" fire frequency and to include the five noted zones in the population of "cable spreading rooms."

Examination of Table 8.5-2 in the STP PSA (Reference 1) indicates some apparent discrepancies in the allocation of fire frequencies among these five cable zones. For example, on page 8 of Table 8.5-2, zones Z026 and Z047 are correctly included in the "Cable Spreading" category. The total annual frequency of cable spreading room fires (6.70E-03 fire per year) is distributed between these two zones. However, on page 2 of Table 8.5-2, zone Z047 is also included in the "Mechanical and Electrical Auxiliary Building" category with a correspondingly lower annual fire frequency. Zones Z010, Z057, and Z060 are also included in the "Mechanical and Electrical Auxiliary Building" category. The fire frequency of 1.07E-03 fire per year from page 2 of Table 8.5-2 was assigned to Zone Z047 in the quantitative screening analysis. Because of the time that has transpired and the unavailability of some key personnel who performed the original analysis, we are unable to reconstruct the reasons for theses apparent discrepancies.

A sensitivity study was performed to examine the quantitative effects from reassignment of the five questionable fire zones to the "Cable Spreading" category. The first step of this study was to determine an appropriate generic annual fire frequency for cable spreading rooms. It is noted that the generic database for cable spreading room fires includes three events (Reference 2). One of these events involved a relay fire. This event is not applicable for any of the five STP cable zones because none of these zones contain any relay cabinets. However, the event was retained in

(FIRE-ATT1)

the database for this sensitivity study, and the generic annual fire frequency of 6.70E-03 fire per year shown on page 8 of Table 8.5-2 was conservatively used as the basis for these calculations. It has also been noted that many "generic" plants have somewhat less equipment and fewer cables than STP. To account for the possibility that STP has more cable spreading room area than a "typical" plant, the generic annual cable spreading room fire frequency was conservatively increased by 50% to yield a value of 1.01E-02 fire per year. This scaling practice is not typically applied in other fire risk analyses, and it was used in this sensitivity study only to provide an upper bound estimate for the quantitative effects from reevaluating these five fire zones. A more realistic analysis would remove the relay fire event from the generic cable spreading room fire database and would more carefully assess the actual cable spreading room area at STP compared with areas in "typical" two-train plants.

The scaled total annual cable spreading room fire frequency was allocated among the five STP fire zones according to their floor areas shown in Table 8.5-2. The results from this allocation are shown below and are compared with the annual fire frequency used for each zone in the original quantitative screening analysis.

Zone	Area	Original Annual Fire Frequency	Revised Annual Fire Frequency
Z010	7,877	1.15E-03	2.48E-03
Z026	7,907	3.48E-03	2.48E-03
Z047	7,320	1.07E-03	2.30E-03
Z057	5,779	8.46E-04	1.82E-03
Z060	3,100	4.54E-04	9.74E-04
Total	31,983	7.00E-03	1.01E-02

It is interesting to note that the original total annual fire frequency for these five zones is very close to the unscaled "generic" cable spreading room value of 6.70E-03 fire per year. However, the allocation of this total among the zones is somewhat skewed by the different treatment of zone Z026. It is expected that a more realistic evaluation of the revised annual cable spreading room fire frequency (removing the relay fire event and appropriately scaling the generic frequency to account for the STP cable room area) would yield a total that is also close to this value.

The revised annual fire event frequency for each cable zone was next propagated through the quantitative screening process applied for all STP fire zones. This process is described in Section 9.3 of the STP PSA final report and in responses to previous review questions. The original fire zone screening analysis applied a quantitative criterion that stated that an end state was screened from further investigation if its estimated annual core damage frequency was less than one-tenth of one percent of the total core damage frequency from all other internal initiating events; i.e., less than 1.7E-07 event per year. The results from this sensitivity study indicate that one fire event scenario end state from zone Z010 and five end states from zone Z047 fail to meet the original quantitative screening criterion when the revised initiating event frequencies are applied. The frequencies of all end states from zones Z026, Z057, and Z060 remain below the criterion. The six end states and their revised estimated core damage frequencies are shown below.

Zone	End State	Original Estimated Core Damage Frequency	Revised Estimated Core Damage Frequency
Z010	6	1.36E-07	2.93E-07
Z047	53	1.44E-07	3.16E-07
	54	1.63E-07	3.58E-07
	90	9.05E-08	1.99E-07
	101	7.87E-08	1.73E-07
	107	9.16E-08	2.01E-07

Reduction factors to account for the fire zone geometry and fire severity were applied during the original screening analysis for only end state 53 from zone Z047. No reduction factors were applied for any of the other end states, and no additional reduction factors were applied for end state 53 during this sensitivity study. Based on experience from the original analyses, it is expected that application of conservative geometry and severity factors would reduce the frequency of each of the other end states well below the screening criterion.

It is not known why the original fire event frequencies for zones Z010, Z047, Z057, and Z060 were derived from data for "auxiliary building" fires rather than "cable spreading room" fires. However, it is concluded from this sensitivity study that reallocation of the annual fire frequency for "Cable Spreading" areas among the five relevant fire zones at STP has a negligible quantitative impact on the results or conclusions from the original analysis. Only 6 of a total of 72 end states from these five zones failed to meet the original quantitative screening criteria after their frequencies were adjusted. The estimated total core damage frequency from these end states is less than one percent of the core damage frequency from all other internal initiating events.

Several significant sources of conservatism remain in the calculations performed for this sensitivity study. One of the three events in the generic database for cable spreading room fires involved a relay fire that is not applicable to the cable zones at STP. Removal of this event from the database would reduce the applicable generic annual fire event frequency. The generic annual fire event frequency was also arbitrarily increased by 50% to account for the possibility that STP contains significantly more cable areas than a "typical" plant. This assertion has not been confirmed. The practice of scaling generic fire event frequency data has also not been typically applied in other contemporary fire risk analyses. Conservative reduction factors to account for the fire zone geometry and fire severity have been applied during the analysis of only one of the six end states that fail to meet the quantitative screening criterion. It is expected that the application of similar conservative reduction factors to each of the other end states would reduce their frequencies well below the screening criterion. It is also expected that a more detailed assessment of end state 53 for zone Z047 would reduce its frequency. Based on this sensitivity study and its associated conservatisms, the conclusion that fires at STP are an insignificant contribution to the total frequency of core damage remains valid.

References

1. Pickard, Lowe and Garrick, Inc., "South Texas Probabilistic Safety Assessment," prepared for Houston Lighting & Power Company, PLG-0675, May 1989.

2. PLG, Inc., "Database for Probabilistic Risk Assessment of Light Water Nuclear Power Plants," PLG-0500, Volume 8, Fire Data, Revision 0, September 1990.

Question 2. Provide the basis for screening area Z032 from further analysis in the STP Internal Fire Analysis.

Response

The STP PSA spatial interactions analysis identified zone Z032 as a potentially important fire area. This is documented by inclusion of scenario Z032-FS-01 in the "List of Important Hazard Scenarios for Further Analysis in STP PSA," Table 8.6-7 of the STP PSA final report. However, this scenario was inadvertently omitted from the list of mechanical and electrical auxiliary building fires evaluated in Section 9.3 of the STP PSA report and from the list of control room fire scenarios evaluated in Section 9.4.

To consistently evaluate the potential risk significance from fires in this zone, a sensitivity study was performed for zone Z032, using the same methodology previously documented for all other fire scenarios listed in the STP PSA final report, Table 9.3-1. The most important equipment in this zone consists of the first row of cabinets and their associated cables. This row contains solid state protection system (SSPS) train R logic cabinet ZRR01, engineered safety features actuation system (ESFAS) train A actuation cabinet ZRR02, ESFAS train A test cabinet ZRR03, ESFAS train B actuation cabinet ZRR04, ESFAS train B test cabinet ZRR05, ESFAS train C actuation cabinet ZRR06, ESFAS train C test cabinet ZRR07, and SSPS train S logic cabinet ZRR08. All cabinets are separated from each other by double wall construction. An air gap of approximately 2 inches is also provided between each set of cabinets for different safeguards functions. (For example, there is an air gap between SSPS cabinet ZRR01 and ESFAS train A cabinets ZRR02 and ZRR03; there is also an air gap between ESFAS train A cabinets ZRR02 and ZRR03 and ESFAS train B cabinets ZRR04 and ZRR05.) There are no lateral penetrations between any cabinets in this row. All cables exit through either risers into the overhead cable tray network or floor penetrations into the cable spreading area on the next floor below.

All ESFAS train A cables exit cabinets ZRR02 and ZRR03 through the cabinet floors into the train A cable spreading room below. Some nonessential equipment cables (designated division "N") exit through the tops of these cabinets into the overhead trays. However, none of the overhead trays in this zone contain any cables that affect operation of safeguards train A equipment.

ESFAS train B cables exit through the tops of cabinets ZRR04 and ZRR05 into an overhead vertical stack of four horizontal cable trays that run parallel to the cabinet row and are offset approximately 8 inches to the east of the closest cabinet edges. These trays distribute the train B cables to risers on the south end of the room that penetrate the ceiling into the train B cable spreading room above.

ESFAS train C cables exit through the tops of cabinets ZRR06 and ZRR07 into an overhead vertical stack of four horizontal cable trays that run parallel to the cabinet row and are offset approximately 8 inches to the west of the closest cabinet edges. These trays distribute the train C cables to risers on the north end of the room that penetrate the ceiling into the train B cable spreading room above.

None of the train B cable trays pass over the train C cabinets or any of the trays containing train C cables. However, some of the train B trays are routed relatively close to and above the train A cabinets. None of the train C cable trays pass over the train A or train B cabinets or any of the trays containing train B cables. All cables in this zone, including the nonessential cables in division "N," meet the flammability criteria of IEEE Standard 383.

The spatial interactions analysis identified zone Z032 as potentially important because it was assumed that any fire in this area would completely disable all three trains of safeguards equipment and lead directly to core damage. This assumption is inappropriately conservative. A quantitative screening analysis was performed to more realistically estimate the potential core damage frequency contribution from fires in this zone. This analysis evaluated the effects from small cabinet fires, large cabinet fires, cable tray fires, and transient combustible fires based on data from the PLG fire event database. Propagation of extremely large cabinet fires to adjacent overhead cable trays was also considered.

During this screening analysis, all of the original fire frequency modification and reduction factors were reviewed for consistency with the sensitivity calculations performed for other fire zones in STP PSA Table 9.3-1. As a result of this review, the initiating event frequency for all fires in zone Z032 was revised from the value of 9.84E-05 fire event per year shown in STP PSA, Table 8.5-2, to a value of 5.90E-04 fire event per year. The higher frequency was then used as the basis for allocating fires among the cabinets and cable trays located in this zone.

The screening analysis results indicate that the largest core damage frequency contribution from any credible fire scenario in zone Z032 is approximately 4.0E-08 core damage event per year. This value is well below the quantitative screening criterion of one-tenth of one percent of the total core damage frequency from internal initiating events; i.e., less than 1.7E-07 core damage event per year. The most important fire scenario includes a large cabinet fire that damages the train A ESFAS cabinets and propagates to the nearest train B cable tray. It is assumed to cause a small LOCA due to short circuits that open pressurizer PORV PCV-655A, and it is assumed to disable all safeguards equipment in trains A and B.

It is noteworthy that the stuck-open PORV could be isolated by closing its motor-operated block valve MOV RC0001A. Operability of this valve is not affected by any fires in zone Z032. It is also noteworthy that fires in this zone can disable only automatic safeguards actuation signals and manual signals from the main control room switches. The operators could manually start and operate all necessary safeguards equipment from the auxiliary shutdown panels by disconnecting the normal control circuits at the switchgear room transfer panels. However, neither of these possible recovery actions were included in the screening analysis.

The results from this sensitivity study confirm the fact that fires in zone Z032 are negligible contributors to the frequency of core damage at STP. The quantitative impact from all fires in rooms classified within the control room envelope is completely dominated by the small set of main control panel fires evaluated in Section 9.4 of the STP PSA final report.

Question 3

Provide a discussion of the effect of weighting the fire initiating event frequency for personnel traffic on the overall fire contribution.

Response

The rules for allocating the frequency of MEAB fires among the individual MEAB fire zones are not documented in the STP PSA final report. However, the rules can be inferred by examination of the actual numerical frequency assignments. These rules are shown in Table 1.

Table 1. Inferred MEAB Fire Zone Frequency Allocation Rules

Rule	Condition	F_{mod}
1	Occupancy = "Cable"	0.25
2	Occupancy = "Cable, Cabinets"	0.75
3	Occupancy = "Piping"; Traffic <0.25	0.125
4	Occupancy = "Piping"; Traffic >0.50	0.375
5	Occupancy = "Power Cable"	0.75
6	Occupancy = "Power Cable, Cabinets"	1.00
7	Occupancy = "Power Cable, Cabinets, Battery"	1.50
8	Occupancy = "Power Cable, Switchgear"	1.875
9	Occupancy = "Pumps"	1.50
10	Occupancy = "Power Cable, Valves"	1.00
11	Occupancy = "Transient"	0.125

The rules shown in Table 1 were applied directly to 95 of the 111 fire zones in the MEAB. The table shows that the zone traffic level enters the allocation rules only for zones whose primary occupancy consists of piping. These zones are

Z030, Z032, Z062, Z063, Z065, Z066, Z082, Z105

The first level of the screening analysis eliminated all of these fire zones as quantitatively insignificant. Since the traffic level does not enter into the frequency allocation for any of the remaining 87 zones, it can be concluded that the assessed traffic levels shown in Table 8.5-2 of the STP PSA final report have an insignificant impact on the overall fire risk contribution from these zones.

The rules documented in Table 1 were applied to 95 of the 111 MEAB fire zones. For the remaining 16 zones, additional modification factor adjustments were made to account for zone-specific conditions. These 16 zones are

Z006, Z019, Z023, Z028, Z033, Z061, Z093, Z096, Z104, Z117, Z123, Z124, Z125, Z141, Z142, Z143

None of the numerical adjustments to these zones are very large. The first level of the screening analysis eliminated 14 of these fire zones as quantitatively insignificant. The remaining two zones, Z006 and Z142, were evaluated more extensively in the second and third levels of screening. For zone Z006, an adjusted final modification factor of 1.50 was applied. This factor is higher than the factor of 1.00 that is normally assigned to this type of zone. Therefore, the estimated fire event frequency for this zone in the STP PSA is approximately 50% higher than the frequency that would be calculated by other methods. The quantitative screening evaluation for zone Z006 has shown this zone to be an insignificant contributor to the overall risk from fires. For zone Z142, an adjusted final modification factor of 0.75 was applied. This factor is somewhat lower than the factor of 1.00 that is normally assigned to this type of zone. The detailed fire scenario end states for this zone were reexamined to determine the effects from increasing the initiating event frequency by 33%. All end state frequencies remain below the applied quantitative screening criterion of one-tenth of one percent of the core damage frequency from all other internal initiating events; i.e., less than 1.7E-07 event per year.

Based on these observations, it is concluded that neither the assessed traffic levels documented in Table 8.5-2 of the STP PSA final report nor the additional adjustments to the 16 specific fire zone frequency allocation factors have a significant impact on the overall contribution of fires to core damage at STP.

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10. SUPPLEMENTARY NOTES

11. ABSTRACT *(200 words or less)*

The objective of this review is to evaluate the South Texas Project (STP) Probabilistic Safety Analysis (PSA) for the USNRC. The PSA was reviewed for thoroughness of analysis, accuracy in plant modeling, legitimacy of assumptions, and overall quality of the work. The review is limited to the internal event analysis and the fire accident analysis.

This review is not a pass/fail evaluation of the adequacy of the PSA. The adequacy of the analysis depends on the intended uses and must be addressed on a case-by-case basis by the licensee and the NRC. This review identifies strengths, weakness, and areas where additional clarification would assist the NRC in evaluating the PSA for specific regulatory purposes.

The licensee, Houston Lighting and Power (HLP), reviewed this report prior to its final release to the NRC. The responses provided by HLP are provided in detail in appendices to this report, and they are summarized in the main body of the report. All issues raised in the review were adequately addressed by HLP in their responses.

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