01C

# BROOKHAVEN NATIONAL LABORATORY

## MEMORANDUM

DATE: January 23, 1984

TO: R. A. Bari

FROM: M. A. Azarm, C. Ruger, and J. L. Boccio

SUBJECT: Status of GESSAR Review: Fire

Our review of the GESSAR II Fire and Flood External Event Analysis document(1), prepared by the General Electric Company, has reached an impasse. Prevalent to this state of affairs is the fact that (1) the document is not a "stand alone" study of the risks associated with fires within the plant, and (2) we have not, as yet, received from the utility any responses to our initial inquiries that were submitted to NRC by letter dated Dec. 6, 1983.

This lack of completeness and utility responsiveness notwithstanding, the purpose of this memo is to amplify further our initial findings. As has been the case in our review of the LIMERICK SARA, the team assigned to review "GESSAR II - Fire" had a dual function. One is to critique those deterministic fire models employed in the analysis; the other, to assess the probabilistic methods and data employed for determining the frequency of fire-induced initiating events. The results of this effort are then reported to those within the Risk Evaluation Group assigned to review the bottom-line risk numbers, viz, core-melt frequency. For completeness, the scope of our review also entailed the gathering of information from a companion document - the GESSAR II Fire Hazards Analysis.(2)

<u>Probabilistic Fire Analysis - A Preview</u>

At the outset, we must state that with the incorporation of many fire-protection features within the generic plant, the core-melt frequency from fires is expected to be comparatively lower than those from other plants. Primarily, this is due to strict compliance to requirements set forth in Appendix R to 10 CFR 50 in Section 9.5.1 of the Standard Review Plan (SRP). However, corroboration of this expectation, through quantitative analysis, has been hampered from the lack of completeness of the document under review. Also, in certain respects, the document does not contain the necessary elements or steps currently associated with what is perceived to be the state-of-the-art in probabilistic fire-risk assessment. This, coupled with the prevailing large uncertainties in fire-risk analysis, precludes making any viable judgments or appraisals on the cited document.

The scope of our review is, therefore, limited to (1) generic discussions on specific fire protection features designed into the GESSAR II plant; (2) their potential impact on fire-risk analysis; and (3) to the extent possible, a summary appraisal on the <u>existing</u> GESSAR fire-risk analysis.

## General Discussion

Several probabilistic fire-risk studies have already been performed[3-6]. In almost all of these studies, fire is one of the major contributors to the overall plant risk, dominated by fire occurrences in a few areas where electrical cabling and equipment of redundant shutdown divisions are either mutually located or do not meet specific fire protection requirements. Thus, the methodologies developed for probabilistic fire-risk assessment basically address single enclosure fires, and the contribution of risk due to a fire spreading beyond the rated barriers has been judged to be negligible compared to single enclosure fire risk.

For a single enclosure fire, three stages of fire propagation are usually considered[4]. First stage growth is construed as damage to components in the immediate vicinity of the fire source which usually causes the initiating event (reactor scram and other transients). The second stage consists of fire growth to adjacent unprotected cable raceways, separated from the initial fire by the minimum separation criteria (5 ft. vertically and 3 ft. horizontally). Third stage fire growth represents fire of sufficient severity and duration to damage mutually redundant shutdown methods separated by at least 20 ft. or else protected by rated barriers (usually 1/2 hr. to 1 hr. rated blanket). For those plant designs and areas, where cabling and/or the equipment used for redundant shutdown methods are located, the third stage of fire growth within these areas usually yields the dominant fire-risk contributors.

In the GESSAR II Plant design, cabling and equipment associated with the redundant shutdown methods are (in most cases) separated by three-hour rated barriers. (There are a few exceptions that are discussed in detail in the fire hazard analysis report.) Minimizing fire growth through efficient utilization of these barriers has three impacts on existing fire-risk assessment methodologies, viz.,

1) conceivably, fire risk is reduced because the contribution of third stage fire growth is lessened. However, the contributions of Stage 1 and 2 fire growth may now be comparable or even more than the Stage 3 fire growth. Hence, it is important to consider all the areas of the plant where a fire can cause an initiating event (first stage growth).

2) The third stage fire growth (now defined as fire spreading through three-hour rated barriers and penetrations) necessiates consideration for multi-enclosure fire spread and thus differs from the various fire PRA's performed thus far for single enclosure fire growth.

3) A fire in high fuel load areas, contiguous to critical areas containing safety systems, may impose a threat to plant safety. Although the probability of fires with enough severity and duration to cause barrier failures may be small, their inclusion in probabilistic fire analysis for plant design, such as GESSAR II, cannot be disregarded.

As such, estimating the fire risk under these circumstances requires that the above factors be considered. The first can be complied with if all areas of the plant that may induce an initiating event or contain safety-related equipment or cabling, are included in the study. The remaining can be addressed by bounding analysis on barrier failures(7) and construction of an adjacency matrix(8) to identify the critical multi-enclosures fire scenarios. Once the critical multi-enclosures fire scenarios are identified, the detailed probabilistic modeling can be performed by means of various methodologies such as those given in References 9 and 10.*

The GESSAR Probabilistic Fire Analysis report appears not to have included these three factors systematically. Hence, questions as to completeness of the study and efficiency of the numerical results prevails. Note that the additional elements, discussed above, have yet to be implemented in conventional fire probabilistic risk studies and that further research in this area may be required. However, given the existing methodologies, some of the concerns mentioned above could have been addressed for GESSAR II plant, at least through a bounding analysis.

Specific Discussion

Our specific comments and questions on the GE report on probabilistic fire analysis for GESSAR II are given below. These comments are on the screening analysis used; the fire frequencies employed; fire propagation and suppression models incorporated; and, the quantification of fire-induced core melt probability.

- Screening Analysis

Although a GE screening analysis has identified six critical fire areas, there is little discussion and almost no documentation as to how the analysis was performed. (It is stated that the areas identified through the screening analysis are basically the same as those suggested by the NRC.) In addition, the consequence of fire in the diesel generator building is considered negligible under the assumption that the diesel generator catches fire while in the standby mode. However, actuarial data on fire in nuclear power plants indicates that the frequency of a diesel generator catching fire per demand is about $7.4 \times 10^{-4}$. Hence, a fire scenario starting with Loss of Off-Site Power (LOSP) and imposing demands on the diesel generators may result in a diesel generator fire while it is not in a standby mode. Given the existence of three diesel generators in GESSAR II plant and the frequency of LOSP of about 0.22/year, a frequency of $4.8 \times 10^{-4}$/year can be assigned to this fire scenario (LOSP with loss of one diesel).

---

* These two references may also provide some insight into determining fire-barrier effectiveness.

Therefore, BNL cannot address the adequacy of the screening analysis performed for GESSAR II plant without obtaining and reviewing further documentation on this subject.

- Fire Frequency

The GESSAR report states that the annual fire frequency for the critical fire areas are estimated based on the actual fire data in nuclear power plants[11]. However, no discussion on either the data used or on the estimation process employed is provided in the report. Reference (12) lists data on building fire frequency based on the actual data given in Reference (11). These estimations are given in Table 1. It has been our recommendation that the data for self-ignited cable fires be reduced by a factor of three to account for the use of proper splices, overrated and flame retardant cables[13]. Furthermore, the resultant frequency for self-ignited cable fires can be specialized to a specific fire zone in a building by the ratio of the actual combustible weight or area in the room to the total combustible weight or area in the building.

It is also not clear how the annual fire frequencies for the critical areas are estimated in GESSAR II Probabilistic Study. Specifically, the p-factor, defined in the study as the ratio of combustible area to the room area, may only be justified for the transient fires if one takes into account the critical distances given in Table 2-2 of the GESSAR II Fire Probabilistic report. Again, without further documentation explaining how the fire frequencies are estimated and what is the logical interrelation between the p-factor and the fire frequency in the critical areas, we will avoid any judgment on the accuracy of fire frequency estimates.

- Zone Specific Comments

Control Room

The scenario considered for the control room starts with a fire in a panel which is confined to a cabinet. Propagation to other cabinets is judged to be negligible. It is stated that the cabinet design given in Figure A illustrates features which mitigate the spread of fires. However, the report does not contain Figure A. It is also stated that there is 0.2 chance of cable ignition. It is not clear to us what cables are considered and how the 0.2 chance was estimated. There is no indication which cabinets are critical and how the p-factor was estimated.

In conclusion; we recommend for the control room fire a bounding analysis be performed (similar to the one done in Reference (4)), taking into account the plant-specific fire protection features.

Control Equipment Room

The same comments as above are applicable.

Electrical Equipment Room (Control Building)

A fire scenario, starting with a fire in a termination cabinet, disabling a safety division and then propagating to other divisions is considered. The following assumptions are made for quantification of this scenario:

1. It is assumed that it takes 10 minutes for a fire to disable a division of safety cables.

2. The probability for fire to propagate 20-feet to another division is assumed to be 0.5.

3. The propagation of fire through the termination cabinet, a three hour rated wall, 50 ft. of separation and another three hour rated wall is assumed to be $5.0 \times 10^{-6}$.

Given the assumption that there are no exposed cables in this room, the above estimates, although judgmental, may be appropriate. However, the event tree developed for this fire scenario attempts to combine the two electrical equipment rooms together. This combination results in an underestimation of the core melt frequency. The proper estimates can be obtained if two similar event trees for each electrical equipment room fire scenario be constructed and quantified. In addition, the p-factor used for these areas can be neither justified nor understood.

Cable Tunnel

The cable tunnels are located at each side of the control room. Divisions 1 and 4 are located on one side of the control room, while Divisions 2 and 3 are located on the other side. Cabling in Divisions 3 and 4 runs through conduits embedded within three-hour resistant concrete exterior walls. The analysis performed for the cable tunnels resembles that of the Electrical Equipment Room with the exception that the probability of suppression for the first 10 minutes is assumed to be 0.9. Hence, our critique of this fire zone is similar to that given for Electrical Equipment Room.

Auxiliary Building (Electrical Equipment Room and Zone 1 Corridor)

The analysis is not clear at all. There are two auxiliary electrical equipment rooms and two corridors of concern (Zone 1 and 2). It is not clear why only the Zone-1 corridor and one of the auxiliary Electrical Equipment Rooms are considered. There is some Division 4 cabling and equipment in addition to Division 1 equipment in this area which is not considered. The initiating event (fire induced transient type) is not known. The scenario for which the suppression failure probabilities are estimated is also not known.

In conclusion, for these two fire zones in the auxiliary building, further documentation on the component layout and methodological approach is required.

Deterministic Fire Analysis - A Preview

Deterministic fire growth modeling is used in the GESSAR II Fire External Event Analysis to determine the occurrence of secondary fires to initiate and subsequently grow when fire propagation is indicated. The resultant fire growth times then serve as input to the probabilistic methodology from which the failure probability of fire suppression is factored into the accident sequence progression.

The specific deterministic fire growth model used is the computer code COMPBRN[14,15]. This code is a synthesis of simplified, quasi-steady unit models resulting in what is commonly referred to as a zone approach model. Our general evaluation of the deterministic models employed in COMPBRN appears in the Limerick SARA review[13].

The application of this deterministic model in the GESSAR II Fire External Event Analysis is somewhat difficult to review. No COMPBRN calculations have been performed specific to the GESSAR II plant geometry. Instead, total reliance for deterministic calculations is placed on COMPBRN computer runs performed for the Zion[3] and Limerick[4] PRA's. This lack of a self-contained document complicates the review process.

Notwithstanding, this segment of the overall review consists of two parts. The first contains some general comments regarding the completeness of the analysis while the second concerns the application of the calculational results to the GESSAR II scenario.

General Discussion

A significant portion of the electrical cabling in the GESSAR II plant is routed through conduit embedded in concrete as in the Cable Tunnel. Fires can occur in areas surrounding these conduits and depending on the external heat load, combustible vapors may be produced inside the conduit due to the pyrolysis of the cable insulation. These vapors will not ignite near the heat source since they are physically separated from the ignition source by the concrete conduit. However, these combustible vapors can migrate to adjacent fire areas through the conduit penetrations. At conduit termination points, which are likely to be within an electrical cabinet, these vapors can ignite when provided with an ignition source such as a spark from equipment in the cabinet. This form of inter-area fire propagation has not been considered in the GESSAR analysis and can lead to investigation of additional scenar .

A somewhat similar concern is the inter-area propagation of smoke. Areas such as the Control Room and the Zone 1 Corridor, which contains the remote shutdown panel, have been assumed to remain operational during fires in other areas. Therefore, consideration should be given to the possibility of smoke propagation to these areas from fires in adjacent areas rendering them inhabitable thereby affecting the success probability for achieving safe shutdown.

There is an inconsistency regarding the consideration of transient combustible fires in the GESSAR analysis. Table 2-1 indicates that significant transient combustibles are present in the Cable Tunnel and Auxiliary Electrical Equipment Room. However, no analysis are included to account for fires initiating with transients such as an oil pool fire.

Deterministic Model Application

As noted earlier, the GESSAR II analysis relies heavily on assessment and calculations contained in the Limerick SARA[4] analysis. However, there appear to be many inconsistancies between the physical situations analyzed in the Limerick and GESSAR plants which precludes drawing any meaningful conclusions based upon the identical analyses employed.

For example, in the Control Room and Control Equipment Room, the GESSAR analysis states "the probability of propagation of the fire beyond the panel to cables was assessed to be 0.04...". This appears to be taken from a judgmental assessment in the Limerick SARA for the Safeguard Access Area, where panel fires that propagate beyond the confinement of the panel and ignite adjacent cable raceways prior to suppression are considered. Since none of the reported panel fires propagated in such a manner, an upper bound was assumed in that one in five reported fires propagates. A further five-fold reduction in this upper-bound value was assumed to account for the difficulty of ignition of flame-retardant cable insulation.

In the GESSAR Control Room, where this assessment is applied, the situation is different since there are usually no exposed cables in the Control Room. It is not clear if exposed cables are actually present, if the cables considered are assumed to be internal to an adjacent panel, or if panel-cable raceway propagation was taken to be a conservative estimate of panel-panel propagation. The latter case would yield a highly overconservative probability.

It is also unclear what rationale was employed for concluding that panel propagation has an higher probability than cabinet propagation. The failure to include the referenced Figure A adds to the uncertainty.

Paper is considered as a transient combustible in the GESSAR control room. It is stated that COMPBRN calculations from the Limerick SARA indicate that paper fires are incapable of igniting cable insulation. The calculation in the Limerick analysis considered 2 pounds of paper, 1 foot in diameter, located 10 feet below a cable tray. Again, it is not obvious what the relationship is between this situation and that of a control room paper fire adjacent to a panel or cabinet. In fact, such a scenario was considered in the Limerick analysis, and is included in Table 2-2 of the GESSAR analysis, in which this paper fire is found to be capable of damaging the internal components of a cabinet when within 1 ft. of the cabinet wall. It is unclear why the cable damage analysis was cited rather than this cabinet analysis.

For the Control Building Electric Equipment Room, the GESSAR analysis cites a COMPBRN calculation from the Limerick PRA which results in a 0.4 failure probability to suppress a fire in 10 minutes. This 10-minute growth time represents the time interval between the fire self-igniting in a cable tray and spreading to redundant cable trays located at a distance of 5 ft. vertically or 3 ft. horizontally from the initial fire. The failure probability to suppress is taken from the Limerick PRA suppression model (Figure 4-4).

Since Table 2-I of the GESSAR analysis indicates that there is no exposed cable insulation in the Electric Equipment Room, the relevance of the cable tray fire growth time calculation to the cabinets and panels actually existing in the room is unclear. The Limerick SARA review evaluates the models used in the COMPBRN code and indicates that the 10 minute cable tray fire growth time is over conservative.

Summary

Judgmentally, we feel the GESSAR II plant to be relatively free from fire risk. Strict adherence to the criteria and guidelines found in Appendix R to 10 CFR 50 and SRP 9.5.1 are the basis for this qualitative appraisal. Substantive proof, based upon analysis, is however wanting.

If the GESSAR II analysis considers barrier failure to have a finite probability as a result of fires being initiated within critical areas, then the analysis should also include barrier failure from fires that are initiated in those non-critical areas which are contiguous to critical areas of concern.

The use of the p-factor should be justified. Considerations where the initiating event frequencies of fires, within specific areas, are reduced by factors either weighed by the amount of combustibles in the area or by their occupancy, must start with a common basis. That is, the actuarial data employed must also take fuel weight or surface area into consideration before it is applied specifically.

Increasing the fire resistance of barriers and walls by composite construction with fire-resistant materials places greater import on penetration seal effectiveness. This aspect should have been included in the analysis.

Specific fire scenarios discussed within the report do not always correspond to the particular physical situation. Strong emphasis has been placed upon fire situations analyzed in other plants, and, at times, yield inconsistencies as to what is damaged and by what fire-induced stress mechanism.

In short, and with the limitations of the state-of-the-art in fire-risk assessment in mind, we cannot quantitatively appraise the GESSAR II analysis.

REFERENCES

1. General Electric Company, "GESSAR II Fire and Flood External Event Analysis," October, 1983.

2. General Electric Company, "GESSAR II, 238 Nuclear Island Doc. 22A7007, Rev. 2., Appendix 9A.

3. Commonwealth Edison Co., "Zion Probabilistic Risk Safety Study," 1980.

4. Philadelphia Electric Company. "Severe Accident Risk Assessment, Limerick Generating Staton," Report No. 4161, April 1983.

5. Indian Point Probabilistic Safety Study, Power Authority of the State of NY, Consolidated Edison Company of NY, Inc., Spring 1982, Chapter 6.

6. K.N. Fleming, et al., "A Methodology for Risk Assessment of Major Fires and Its Application to an HTGR Plant," GA-A15402, July 1979.

7. Dennis L. Berry, Earl E. Minor, "Nuclear Power Plant Fire Protection - Fire-Hazard Analysis," NUREG/CR-0654, SAND 79-0324, September 1979.

8. Donald A. Duke, "A Systematic Approach to the Identification and Protction From Fire of Vital Areas Within Nuclear Power Plants," SAND 82-0648, October 1982.

9. A Conceptual Approach Towards a Probability Based Design Guide on Structural Fire Safety," Workshop Report, CIB W14 Workshop "Structural Fire Safety," January 1983.

10. Sven Erik Magnusson and Ove Peterson, "Rational Design Methodology for Fire Exposed Load Bearing Structures," Fire Safety Journal, 3 (1980/81) 227-241.

11. "Nuclear Power Experience," Division of Petroleum Information Corporation, Denver, Colorado, December 1981.

12. Kazarians, M., et al., "Fire Hazard and Failure Model," to be presented at ACTA Seminar, Palo Alto, Ca., April 1983.

13. Azarm, M.A. et al., "A Preliminary Review of the Limerick Generating Station Severe Accident Risk Assessment," Volume I: Core Melt Frequency, NUREG/CR-BNL-NUREG Draft, Brookhaven National Laboratory, August 15, 1983.

REFERENCES (Cont'd)

14. Siu, N.O., "Probabilistic Models for the Behavior of Compartment Fires," School of Engineering and Applied Science, University of California, Los Angeles, Ca., NUREG/CR-2269, August 1981.

15. Siu, N.O., "COMPBRN - A Computer Code for Modeling Compartment Fires", School of Engineering and Applied Science, University of California, Los Angeles, Ca., UCLA-ENG-8257, August 1982.

BROOKHAVEN NATIONAL LABORATORY

# MEMORANDUM

DATE: January 25, 1984

TO: R. A. Bari

FROM: I. A. Papazoglou

SUBJECT: GESSAR Internal Flood PRA Review

This memo summarizes the review comments on the GESSAR Internal Flood Analysis to date. A brief preliminary review was conducted by BNL to identify and raise issues, concerns, and questions pertaining to the analysis. It is important that GE responds to these concerns before February 8, 1984 so as to allow BNL enough time to evaluate the GE inputs for inclusion into the final draft report.

1) In the GESSAR Internal Flood Analysis, two water sources were considered; they are potential cracking or rupture of pipes, and leakage from seals and glands. Provide the rationale why internal flood due to maintenance of equipment was not considered in the analysis. Explain in more detail how the effects of draining the suppression pool and/or the condensate storage tank are evaluated for the various potential flood areas.

2) On p.3-6 of the Internal Flood Analysis, it is stated that the instrumentation of the drywell floor drain leak detection system is fed from an uninterruptable power source. Provide additional discussion on the "uninterruptable" power source and on how the value of $2x10^{-3}$ is derived.

3) Industrial data were cited as a basis for assuming certain flood frequencies in different parts of the plant. Indicate the section of the GESSAR SAR from which the information is derived.

4) In the event that there is a pipe rupture at elevations above the bottom level of the building, water will drain into the bottom level through stairways and cable trays, etc. Discuss why the cascading of water from higher elevation which could result in potential common cause failure of systems at lower levels is not considered in the GESSAR analysis.

5) In the Internal Flood Analysis, GE evaluated the scenario of flooding in the diesel generator building leading to a manual shutdown. What is the impact to core damage for a scenario with the simultaneous occurrence of a loss of offsite power and a flooding event in one of the diesel generator buildings.

6) Provide a discussion of the locations of safety system components, instrument panels, and electrical panels with respect to flood height in the GESSAR design.

IAP/dm

ok

BROOKHAVEN NATIONAL LABORATORY

# MEMORANDUM

DATE: January 24, 1984

TO: R. A. Bari

FROM: I. A. Papazoglou

SUBJECT: GESSAR Seismic PRA Review

The purpose of this memo is to summarize the review status of the GESSAR seismic event PRA to date and to highlight the major concerns identified during the review thus far. This review is based on two documents that were submitted to the NRC at two different times: GESSAR II Seismic Event Analysis, September 1983[1] and GESSAR II Seismic Event Uncertainty Analysis, December 1983.[2] On the 9th and 10th of January 1984, a technical information meeting was held between BNL and GE to discuss clarifications of the reports and supplement information needed from GE. Comments presented herein reflect the benefits of that meeting. This memo is organized into two sections. Section 1.0 presents the summary of the GESSAR systems analysis review and was prepared by BNL. Section 2.0 contains comments that are relevant to the seismic hazard and the seismic fragility analyses and was prepared by Jack A. Benjamin and Associates, a consulting firm retained by BNL for this study.

## 1.0 SYSTEM ANALYSIS

In the preliminary review of the systems analysis of the GESSAR seismic event PRA, BNL examined the event tree and fault tree models that were developed in the reports to describe the plant responses to an earthquake. System component and human actions contained in these models were evaluated with respect to their reasonableness and completeness. Since an earthquake is a potential cause for disabling redundant trains or systems, attention was also focused on the treatment of dependent failures between systems. As a

result of this preliminary review effort, the following areas of conern have been identified.

Critical Component List

Since the GESSAR II design is of a generic nature, it appears that previous seismic PRAs would provide a good starting point to identify a list of critical components for consideration in addition to those which may be plant-specific to GESSAR. Review of Table 3-25, p.81, of Reference 1 indicated that only a limited number of components are included in the analysis. BNL compiled a similar list of critical components based on previous seismic event PRAs and on a review of the internal event PRA system fault trees. This list is presented in Table 1.1 and it only contains components that are not addressed in Table 3-25. A discussion should be provided in the report to establish why these components are excluded from the analysis. If they are believed to have large capacity factors, a discussion should be included to explain why the GESSAR components would exhibit such capacities in light of previous analyses and the basis of assurance that the plant to be built would consist of components that are being characterized in the GESSAR analysis.

Instrumentation

Also appearing in Table 1.1 are instrument panels and display instrumentation. It is obvious that instrumentation in general is vital to the operation as well as the safe shutdown of the plant. Failure of instrument panels could lead to the loss of system function. Similarly, failure of various sensors, such as level, or pressure, depending on the failure modes and the number of failures may also result in loss of system functions. It is suggested that additional information be provided to address the failure of instrumentation due to seismic events and its effect upon system performance.

Display instrumentation failure is not considered to result directly in system failures. Oftentimes its principle function is to provide the operator with confirmatory information. In some instances, operator actions as prescribed by the procedures require information from display instrumentation. A detailed discussion should be furnished on the likelihood of common cause display instrumentation failures due to an earthquake and the potential impact upon operator actions given the occurrence of these failures.

Relay Chatter

The relay chatter phenomenon has not been included inthe GESSAR analysis. The effects of relay chatter can be summarized into three different categories. The first case concerns relays that chatter in an earthquake but do not alter the system state through breaker trips after the seismic event. Its impact upon the availability of a system is considered to be minimal. The second case concerns relays that chatter in an earthquake resulting in breaker trips; however, resets of these breakers are located in the control room and can be actuated by the operator to restore a system. A successful system operation in this case is predicated on the recognition by the operator that the system is tripped off line and on the manual reset action of the operator. Lastly, in the event that relays chatter resulting in breaker isolations, resetting of relays may have to be done at local panels away from the control room. Moreover, prior to resetting, careful diagnostic procedures will have to be followed to ensure that indeed no faulted conditions exist. For instance, the in-plant electric circuit will be under this category.

Information should be provided by GE to address (1) the effects of relay chatter upon the availability of the GESSAR systems and (2) the modeling of subsequent operator action to recover breaker isolations.

Human Errors

In the two GESSAR reports, it appears that no consideration was given to the modeling of the increased stress on the operator as a result of an earth-

quake. Subsequent to the onset of a reactor transient or an ATWS, a number of operator actions have been assumed in the GESSAR seismic event trees, a discussion should be provided to justify why the same human failure probabilities were used in light of a seismic event.

Event Tree

BNL performed a preliminary review of the GESSAR seismic event trees and requests that additional information be provided in the following areas in order to facilitate the review.

1) In the development of the GESSAR seismic event tree, the 3 diesel common mode failure is modeled explicitly, Figure 4.1.(1) How is the 2 diesel common mode failure (divisions 1 and 2) modeled in the analysis?

2) It appears that the hardware dependences between the LPCI and the RHR systems are not considered. Provide a discussion on the treatment of dependence between the low pressure core injection and the RHR systems and how it is modeled in the event tree.

3) In the January meeting with GE, BNL questioned the definition of the $E_{DG}$ and $E_{SCB}$ functions specifically with respect to their NOT-event definition. It appears that the NOT-event definitions of these functions in Figure 4.1 is not consistent with the definitions provided in Figures 4.4 and 4.5.(1) GE should furnish a clarification on these event definitions.

4) In the seismic ATWS event tree, Figure 4.3,(1) the level control function by the reactor operator is not included; provide a discussion to support its omission.

5) As noted in the BNL review of the GESSAR internal event PRA, GE has assumed that in the event of an inadvertent ADS, low pressure ECCS is

adequate in mitigating an ATWS if level control is maintained. It appears that a similar assumption is also made in the development of the ATWS event tree. Explain in detail (i) why is there no degradation in the human reliability to control water level, (ii) the procedure that the operator has to follow, and (iii) how much time is available to perform the task.

Fault Tree

1) In Figure 4.12, a 50% value is specified for the failure of the shroud support and a 5% value is assigned for the hydraulic control unit. Provide a discussion on how these values are used in the seismic quantification and the basis for their derivation. If an internal GE document or calculation is referenced, a copy is requested for review.

2) In the GESSAR seismic fault trees, it is noted that failures of pumps and power divisions are modeled as independent events, that is with no correlation. For instance, in Figure 4.11, failure of RHR pumps A and B are considered to be independent basic event. Similarly, the loss of power divisions 1 and 2 are also independent. Provide a detailed discussion to show that in the event of an earthquake, these pumps or the different power divisions would not be subjected to common cause failures and that the assumption of independence is adequate and reasonable for the GESSAR analysis.

## 2.0 SEISMIC HAZARD AND FRAGILITY

This section documents the status of our review of the GESSAR II probabilistic seismic risk assessment (PRA). We have read and studied References 1 and 2 which document the results of the analysis. Dr. John Reed attended a meeting at the General Electric Company (GE) in San Jose, California on 9 January 1984. At this meeting GE discussed the calculations for this component. We have reviewed these calculations. We also have

received a copy of questions prepared by the USNRC which have been submitted to GE for written response.

This section is organized into general comments, seismic hazard analysis comments, and seismic fragility analysis comments. The status of our review and information needed to complete our work is presented below.

General Comments

References 1 and 2 do not provide sufficient information to perform a complete review of the GESSAR II seismic event analyses. Because References 1 and 2 are generic and do not apply to a specific site or plant (i.e., as compared to past PRAs such as the ones conducted for Zion, Indian Point, and Limerick), the ultimate purpose and intended use of the GE analysis is not clear. Based on a preliminary review, the results do not envelop hazard and fragility data from PRAs submitted to the USNRC to date. We request that GE state their philosophy concerning how the seismic PRA analysis will be applied to specific plants. The ultimate use of References 1 and 2 should be defined by GE in order for us to determine if the intended objectives have been achieved.

Many of the questions formally asked by the USNRC express the same concerns that we have. We have not repeated these questions and assume that they will be answered in the near future. Question 720.150 is particularly important, since this question addresses the safety factors for duration, damping, and inelastic energy absorption. It appears to us that the duration factor is the same as the factor used to shift the hazard curves from peak to effective ground motion. This concern should be addressed by GE in response to Question 720.150.

Because the structural capacities are apparently high, the problem of design and construction errors becomes very important. In a practical sense this consideration could dominate the results of the analysis. Since GE has not generally included the effects of design and construction errors in their analysis, they should state why this issue of electrical components also is

not addressed. GE should verify that this is not a problem for GESSAR II. Intergranular stress corrosion cracking has been a problem for GE plants in the past. Is this problem pertinent to GESSAR II plants, and what effect will this problem have on the seismic capacity of piping? Finally, what are the capacities of block walls planned for GESSAR II plants? Are block walls to be located near any safety-related equipment?

Seismic Hazard Analysis Comments

In the GESSAR II seismic PRA a best-estimate seismic hazard curve was developed for the highest seismicity GESSAR II sites, (p.4 of Ref.1). The best-estimate curve is considered by GE to be a realistic, median-centered, upper-bound seismic hazard curve. Further, GE expects that the GESSAR seismic hazard curve will bound site-specific curves at a majority of the potential GESSAR sites at the 50 percent probability level (p.13, Ref.1). The GESSAR II Seismic Event Analysis (Ref.1) was followed by the GESSAR II Seismic Event Uncertainty Analysis (Ref.2), which included an evaluation of the uncertainty in the seismic hazard. An initial review of these reports has been performed. Comments on these reports are given below.

The best-estimate seismic hazard curve developed by GE was based on an enveloping approach. In developing the best-estimate envelope hazard curve, the results of recent utility-sponsored studies and a U.S. Geological Survey study that evaluated ground shaking hazards for the contiguous U.S. were used. The envelope curve selected by GE is considered to be a best-estimate of the extreme values of the best-estimate curves at potential GESSAR sites. It should be noted that the sites which are potential locations for a GESSAR facility are not clearly defined in either GE report. General Electric Company should state what sites the seismic PRA analysis is applicable to.

In the approach used to develop the best-estimate hazard curve, the results of four recent PRA studies were used. They are the Indian Point, Zion, Oyster Creek, and Limerick PRAs. The actual degree to which the U.S. Geological Survey study results were used is not explicitly stated in Reference 1. The best-estimate GESSAR hazard curve was then subjectively

taken as the envelope of the best-estimate curves of the above listed four studies. Further, the GESSAR hazard curve was defined to have an effective acceleration truncation value of 0.95g. The basis for the 0.95g acceleration cutoff is not supported. GE should provide a basis for this cutoff value.

There is no evidence provided in the GESSAR reports to support the statement that the GESSAR best-estimate hazard curve is in fact an upper-bound, or an upper-bound that will not be exceeded by 80 percent of the best-estimate curves at potential GESSAR sites. The arbitrary selection of the four PRA studies used in the GE study, and the subjective manner in which the GESSAR best-estimate hazard curve was selected, raises important questions about the development process and the full meaning of the results. It is not clear, in a probabilistic sense what the GESSAR best-estimate curve represents, other than an envelope of the four hazard curves considered in the study.

With respect to the uncertainty analysis for seismic hazard, a number of concerns are raised about the methodology, data base, and ultimately the final results. In evaluating the uncertainty in the seismic hazard curves, GE elected not to conduct a study that systematically addresses each of the sources of uncertainty in hazard assessment. Rather, they used the results of a published study that polled a group of experts on their estimate of the annual frequency of occurrence of earthquake ground motion levels at various nuclear power plant sites. The results of the expert opinion survey were the basis for making uncertainty estimates.

With respect to the survey itself, several questions as to its adequacy are raised. The experts were given some data on the seismicity in the region surrounding each plant site and asked to provide estimates of the annual frequency of exceedance of ground shaking at each site. Within this format, it is a difficult task for the experts to rationally and consistently provide probability estimates for rare events. An alternative approach is to provide each expert with the opportunity to break the problem into more tangible parts (i.e., seismic source., attenuation, etc.) allowing for a more systematic

evalution, which is less prone to overlooking significant sources of uncertainty and is more easily perceived by the experts in a probabilistic sense.

The study used in the GE analysis was published in February 1975, and undoubtedly performed in 1974. In the last ten years, considerable work has been done in the area of seismic hazard assessment, including solicitation of expert opinion, geologic and scientific investigation, etc. Consequently, the use of the 1975 Okrent study as a basis for uncertainty estimates is seriously questioned. It should also be pointed out that the number of experts used in the study (7) was relatively small. Also, the degree to which those who participated in the survey can be considered probabilistic seismic hazard experts for the entire U.S. is questioned.

We believe that each of the individuals who participated in the survey is a recognized expert in one or possibly more areas of seismic hazard evaluation. However, none of the experts can be considered, nor would they claim, to be experts in all the areas required to make probabilistic hazard evaluations. These areas include, probability, statistics, seismology, geology, ground motion attenuation, local and regional tectonics of each site being investigated, etc. The extensive range of expertise required to make probabilistic seismic hazard assessments is one of the primary reasons for breaking the hazard assessment into integral parts, allowing the experts to deal with each part of the analysis individually.

The results of the expert opinion survey were used as a basis to estimate the coefficient of variation of the annual frequency of exceedance of levels of ground shaking. A preliminary review indicates that the results (Table 2-3, Ref.2) for accelerations less than 0.50g are reasonable in that the uncertainty estimates are consistent with respect to previous site-specific studies and expert opinion surveys. However, at higher acceleration values, which is the region that dominates core melt frequency estimates, the uncertainty values are too small. This also partially explains the reason for the relatively narrow distribution on seismic core melt frequency (Figure 4-2, Ref.2).

The following list summarizes our initial concerns with regard to the GESSAR seismic hazard analysis. We request that GE respond to these concerns.

- The potential GESSAR sites are not identified in References 1 and 2.
- The methodology used to determine a best-estimate hazard curve is probably not adequate to meet GE's objective to produce an upper-bound, best-estimate hazard curve for potential GESSAR sites.
- No evidence is provided to support the statement that the GESSAR best-estimate hazard curve is expected to bound more than 80 percent of the best-estimate curves for potential GESSAR sites.
- The basis for the 0.95g acceleration truncation value for the hazard curves is not provided.
- The 1975 study by Okrent does not appear to adequately provide a basis for the seismic hazard uncertainty estimates. A number of concerns related to the expert opinion survey were raised above.
- The uncertainty estimates at effective acceleration levels greater than 0.50g appear to be low.

Seismic Fragility Analysis Comments

The basis for the fragility analysis is past PRA studies and data which GE has obtained. The information documented in References 1 and 2 is not sufficient to perform a critical review of the GESSAR II seismic fragility analysis. Median capacities are apparently based on generic calculations using the same basic procedures used in past PRAs submitted to the USNRC (i.e., the so called Zion method). We are not able to judge the adequacy of the median values without studying the calculations performed by GE. The variabilities used in the analysis were based entirely on results from past studies, and specific values for structures, components, and equipment were not developed by GE. The following comments and concerns are based on review of References 1 and 2 and the calculations for piping which were provided.

The coefficients of variation assumed in References 1 and 2 for the fragility analysis are generally low compared to past PRA results. It is stated in the calculations for piping that lower values were used because of additional design considerations to be place upon GESSAR plants. It is not obvious why this is so. In fact, because of the nature of GESSAR and the generic analysis performed, the uncertainty should be greater rather than less compared to analyses for specific plants. It is requested that GE provide the bases for the coefficients of variation on the structural capacities assumed in the analysis.

As stated above, there is not sufficient information provided in References 1 and 2 to complete the review. At the meeting with GE on January 9th complete calculations for Reference 1 were requested for all structures listed in Tables 3-2 through 3-18, the eight components in Table 3-19, and the eleven components in Table 25. These calculations are needed to complete the review and to determine the adequacy of the analysis.

The following additional information is also requested. The pages cited refer to References 1 and 2 as indicated:

Reference 1

pg.24: References 9, 10, and 14 do not appear to be correct. What are the correct reference numbers?

pg.35: What is the basis for the strength margin of 1.3 given at the bottom of the page?

pg.38: What is the basis of the 1.2 value assumed for $F_{SS}$?

pg.40: What are the data which substantiate a value of beta equal to 0.2 for inelastic analysis?

pg.42: Was the 10 percent increase cited on this page also assumed for structure capacities? If yes, then were all analyses for the structures performed using the time history analysis method rather than a response spectrum analysis method?

pg.50: The basis for the 30 percent increase for the effect of dynamic yield stress as compared to static yield stress is requested. Note that the explanation given in the calculations for piping for this factor is not clear.

pg.50: Justification should be provided why the damping margin for structures is applicable to the capacities for components and equipment, since at the equipment failure level the supporting structure may be uncracked and still elastic.

Reference 2

pg.3: The basis for the equations for and is requested.

Table 2-3: What are the logarithmic standard deviation values corresponding to each coefficient of variation used in the analysis?

The calculations for piping provided by GE were reviewed. It has been shown in past PRAs the supports are generally weaker then piping. However, in the GE calculations it is stated that support failure due to seismic loads is precluded since supports have been qualified for more severe loads. The basis for not considering failures of the piping supports is requested. Consideration should be given to supports which are designed essentially to resist only seismic loads. Also, consideration should be given to support hardware which is designed for AISC requirements as opposed to ASME criteria (i.e., at the building/support interface).

In order to meet that deadline we need to have all calculations by January 31, 1984 and the response to other questions and concerns by February 8, 1984.

References

1. GESSAR II Seismic Event Analysis, General Electric Company, Sept. 1983.

2. GESSAR II Seismic Event Uncertainty Analysis, General Electric Company, December 1983.

Table 1.1 BNL Critical Component List

Condensate Storage Tank
Diesel Oil Storage Tank
Diesel Oil Day Tank
Burned Pipe
Service Water Pump
Horizontal RHR Pump
Diesel Generator Control Panels
Cable Tray
dc Bus
Battery Rack
Diesel Generator Heat Vent
RPV Support
Reactor Internals
Instrument Panels----------
Display Instrumentation---- |-- see Instrumentation

IAP/dm

GENERAL ELECTRIC

NUCLEAR POWER SYSTEMS DIVISION

GENERAL ELECTRIC COMPANY • 175 CURTNER AVENUE • SAN JOSE, CALIFORNIA 95125
M/C 682, (408) 925-5040

MFN-222-83
JNF-086-83

December 2, 1983

U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Washington, D.C. 20555

Attention: Mr. D.G. Eisenhut
Division of Licensing

SUBJECT: IN THE MATTER OF 238 NUCLEAR ISLAND
GENERAL ELECTRIC STANDARD SAFETY ANALYSIS REPORT (GESSAR II)
DOCKET NO. STN 50-447

APPENDIX 15E - STATION BLACKOUT CAPABILITY

Attached please find a draft of new GESSAR II Appendix 15E pertaining to station blackout capability. This appendix concludes that the GESSAR II station blackout capability exceeds ten (10) hours. The assessed capability assumes credit for operator actions that are straightforward and where means exists to enable the operator to execute the action. Where features and/or equipment are not present, potential design improvements are recommended. It is anticipated that upon completion of NRC review a formal amendment on the GESSAR II docket will be submitted. This is anticipated to occur in early 1984.

If there are any questions on the information provided herein please contact J.F. Quirk at (408) 925-2606 or J.N. Fox of my staff at (408) 925-5039.

Very truly yours,

Glenn G. Sherwood, Manager
Nuclear Safety & Licensing Operation

Attachment

cc: F.J. Miraglia (NRC)
[redacted]
C.C. Thomas (NRC)
R.M. Ketchel (GE-Washington Liaison Office)
L.S. Gifford (GE- Bethesda Liaison Office)
R. Villa (GE)

~~8312060286~~

GESSAR II
238 NUCLEAR ISLAND

DRAFT

APPENDIX 15E

STATION BLACKOUT CAPABILITY

APPENDIX 15E

CONTENTS

## APPENDIX 15E
## TABLES



## APPENDIX 15E
## FIGURES

## 15E.1 INTRODUCTION AND CONCLUSIONS

### 15E.1.1 Introduction

This appendix is provided to demonstrate that the GESSAR II design has substantial capability to prevent a core damaging event well beyond the two-hour value recommended by NUREG-0626 and assumed in the Probabilistic Risk Assessment (Section 15D.3).

Attachment A contains responses to pertinent questions on station blackout of interest to the staff. These are addressed in more detail in other parts of this appendix.

### 15E.1.2 Conclusions

The GESSAR II station blackout capability exceeds ten (10) hours. The assessed capability assumes credit for operator actions that are straightforward and where means exist to enable the operator to execute the action. Where features and/or equipment are not present, potential design improvements are recommended. These operator actions and potential design improvements are summarized below:

1. Operator Actions
   a. Manual RPV Water Level Control with RCIC.
   b. Shift of RCIC pump suction to the condensate storage tank.
   c. Vessel depressurization with SRVs to about 200 psig. Maintain vessel pressure above 150 psig with manual SRV control.
2. Potential Design Improvements
   a. Provide manual logic override of the RCIC suction transfer signal and test line closure signal from the control room.

b. Provide Enhanced Water Level Instrumentation (currently under review for Appendix 1D).

c. Provide alternate power supply to RCIC gland compressor.

An ongoing evaluation of the 125 VDC battery capability is in progress. However, if necessary to ensure 10-hour capability, emergency DC bus cross ties, or larger battery capacity, or other methods will be identified.

In addition to the above actions, the following contingency actions could be taken to provide even longer duration capability are:

1. Provide override capability for the RCIC room high temperature isolation logic to be used if room temperature exceeds about 150°F.

2. Extend SRV pheumatic supply by replacing air bottles if depleted. A connection outside the fuel building would be more convenient.

## 15E.2 DEFINITION OF STATION BLACKOUT

Station blackout refers to the total loss of both off-site and on-site a.c. electrical power. In draft information pertaining to proposed Regulatory Guides, the NRC consultants refer to "Emergency AC" loss in addition to offsite power loss. This could be interpreted as the Division 1 and 2 Standby Emergency Diesel Generators. Both HPCS and RCIC operate at high pressure and can be considered redundant water sources available for maintaining core cooling during design basis assumptions that assume a single failure (i.e., such as a D-G). This configuration is believed to be adequate to comply with the proposed regulatory requirements. For purposes of this assessment,

however, a failure of the HPCS diesel generator has been assumed in addition to loss of offsite power and the division 1 and 2 diesel generators thus providing a more severe impact on plant systems and the station battery.

A one-line diagram of the GESSAR II design is shown in Figure 8.3-1. Three divisions of 6.9 kv on-site power are provided; two by standby emergency diesel generators (in addition to preferred and alternate off-site power sources); the third by an off-site power source and a separate and diverse diesel generator dedicated to division 3 eletrical power. Division 3 supports the High Pressure Core Spray (HPCS) system and all of its supporting auxiliaries.

The GESSAR II design also includes a steam turbine driven Reactor Core Isolation Cooling System (RCIC) which operates in an emergency independently of a.c. electrical power. This system is designed to provide high pressure makeup to the RPV during isolation events and would thus be initiated automatically during a postulated blackout event. The plant response with RCIC alone has been reviewed, and the duration capability of the GESSAR II plant in excess of ten hours has been verified. This configuration is consistent with the station blackout definition in the Probabilistic Risk Assessment (Section 15D.3).

In the evaluation certain assumptions have been made:

- o No Loss of Coolant Accident (LOCA), stuck open relief valve (SRV) or failure to scram concurrent with the station blackout is considered.

- In evaluation of equipment, some capability beyond environmental qualification limits has been assumed. In assessing the ultimate failure capability of equipment the judgement of senior General Electric engineering personnel has been relied upon to provide guidance. Such judgements are explicitly call out in the following sections.
- Operator actions are identified where adequate time and skills would be expected to be available to a typical operating plant staff. No extra-ordinary actions on the part of the operator are assumed; rather, only straightforward, simple actions are allowed.
- No credit for off-site assistance from a utility maintenance crew using portable electric generators or batteries has been assumed for this assessment even though this possibility may exist within the time frame of interest. Such capability might be considered by an applicant to improve the restoration time for on-site emergency a.c. power if the situation warranted.

15E.3 INDICATION OF STATION BLACKOUT

The station blackout event is characterized by a loss of all off-site power (preferred and alternate feeders) and a loss of divisions 1, 2 and 3 of on-site a.c. power. As noted in Section 1D.2.3.33 of the assessment against Regulatory Guide 1.97, the class 1E power distribution system monitors voltage on the three 6.9 kv a.c. buses and the four 125 V d.c. buses. This indication is displayed on panel P800 in the main control room. A potential station blackout event would be first noticed by the plant operators by a change in the control room lighting which would alert him to evaluate both the plant and the electrical distribution system status. By observation of the loss of bus voltage on the 6.9 kv buses "E", "F" and "G" and the breaker position for incoming voltage to these buses, the operator would be alerted to the presence of a potential blackout event. Voltage indication on the d.c. buses E, F, G & H would assure the operator that power is available to control the event.

Prior to conducting the various operator actions needed to mitigate a blackout event, the operator must distinguish between a short duration event and a prolonged blackout. A short duration event would be one in which restoration of an off-site or on-site a.c. power source would occur prior to development of conditions requiring the operator actions

defined later in this supplement. Minimizing the time to recognize this event is important so that the potential drain on the batteries is controlled.

Upon recognition of the a.c. power source failure, an auxiliary operator would be sent to each of the diesel generator rooms to attempt a manual start. Simultaneously, the control room operator should attempt to start each diesel from the main control room. In addition, the system dispatcher would be contacted by the shift supervisor to determine the status and likelihood of off-site power restoration. Accomplishment of these activities in addition to those related to controlling vessel water level and pressure is expected to take about 30 minutes.

Thus recognition of a station blackout event and the initiation of any blackout specific operator actions is expected to be delayed for about 30 minutes.

## 15E.4 INSTRUMENTATION REQUIREMENTS

Instrumentation required to monitor plant status during a blackout event has been selected from a review of the type A through E variables discussed in ~~Section~~ Appendix 1D which is the response to Reg Guide 1.97 requirements. This list has been augmented slightly to account for specific variables such a room temperatures and certain valve and breaker position indications which are needed to determine plant conditions.

Table 1SE-1 lists the variables considered and whether or not they are needed for the blackout sequence. The basis for selection generally is based on the need for the operator to follow Emergency Procedure Guidelines (or take other actions which may later be established) during the period of interest. As such, type A variables are identified as needing indication during the blackout event while variables which are more representative of monitoring core damage or breaks of the reactor coolant boundary or effluent release are excluded.* [redacted]

Table 1SE-2 shows the power supplies in the GESSAR II design for the instruments needed. All indications needed to follow the blackout event are or will be powered from 125V d.c. sources.

The applicant could [redacted] provide d.c. backup ~~backed~~ power to the condensate storage tank level indicator and to ensure local control room temperature indication as available.

---

* Since releases stemming from a postulated station blackout event are within existing design bases events for upset conditions.

# 15E.5 PLANT RESPONSE FOLLOWING A STATION BLACKOUT

The key plant areas which could potentially effect the ability of the plant design to accommodate a station blackout are:

- o RCIC room
- o Remote shutdown panel area
- o Suppression pool and containment
- o Drywell
- o Control room
- o Fuel pool

In addition non-electrical a.c. plant energy supplies will be consumed and need to be addressed to assess the plant capability. These are:

- o Pneumatic Air Supply System (ADS)
- o D.C. Power Distribution System

These areas and energy supplies will be discussed in subsequent sub-sections. An estimate of limiting condition, design improvements [redacted] or operator actions needed are noted in each.

## 15E.5.1 Areas

### 15.E.5.1.1 ~~Area:~~ RCIC Room

a. Reason for Concern

- Room temperature increase without area cooling could cause a loss of RCIC control due to equipment failure.
- Isolation and turbine trip due to leak detection system trip. (Trip setpoint approx. 170°F) could prevent RCIC from operating .
- Steam line drain valves may fail after air supply becomes exhausted causing system damage on restart.

b. Plant Response

- Approx. 122°F in 12 hours (w/CST suction)
- Approx. 133°F in 12 hours (w/SP suction)
- Approx. 101°F in 12 hours (w/10 lb/hr steam)

See Attachment B

| Critical Components | Limitation |
|---|---|
| EH Differential Coil | Approx. 170°F water temp. |
| Magnetic Speed Sensor | 225°F |
| Instrumentation | 212°F |

Capability >12 hrs

c. Assumed Operator Actions

- Manual switch of RCIC suction to CST at about 30 min.
- Override RCIC high temp isolation if room temp > approx. 150°F (not expected)
- Manual RPV level control of RCIC to avoid L8 trip and restart.

d. Potential Modifications/Actions

- Ensure override capability exists for RCIC room isolation signal.
- Ensure override capability for RCIC suction transfer.
- Provide logic changes to permit low flow RCIC injection. Requires override capability on test line to CST to obtain flow split between CST return and vessel.

15E.5.1.2

~~Area~~: Remote Shutdown Panel Area

a. Reason for Concern

- o RCIC electronics could fail if area temperature exceeds 150°F.
- o Access needed if control room uncomfortable or electronics erratic.

b. Plant Response

- o Not evaluated, but very little heat source. ~~S~~since Remote Shutdown Station panel is deenergized until control transfer switch is thrown.
- o Expect area temperature to remain <150°F for 20 hours

| |
|---|
| Capability >20 hrs |

c. Assumed Operator Actions

None.

d. Potential Modifications/Actions

None.

15E.5.1.3
~~2 Area:~~ Suppression Pool

a. Reason for Concern

- High suppression pool temperature could cause NPSH limits (approx. 175°F) and reduced lube oil cooling to RCIC.
- High suppression pool level causes suction transfer.
- High containment air temperature may cause erratic RPV indication.
- High suppression pool temperature and level increases containment loads.

b. Plant Response

| time (hrs) | $T_{sp}$ (°F) | $T_c$ (°F) | $L_{sp}$ (ft) |
|---|---|---|---|
| 1 | 135 | 100 | +2 |
| 5 | 190 | 175 | +5 |
| 10 | 220 | 220 | @ weir |
| 15 | 225 | 225 | @ weir |
| 20 | 230 | 230 | @ weir |

Notes: $T_c$ based on $T_{sp}$ + judgment
$T_{sp}$ based on Table 15D.2-2 calculation

Capability >10 hours.

Instruments qualified to 185°F; capability likely to 250°F.

c. Assumed Operator Actions

- Manual switchover back to CST within 1 hr. eliminates potential NPSH problem.
- Maintain vessel pressure below heat capacity temperature limit per EPGs - ensure written procedures contain heat capacity temperature limit curve [redacted] - may need to exceed heat capacity temperature limit slightly after approx. 6 hrs, but acceptable because no additional depressurization required. Consistent with EPGs.

d Potential Modifications/Actions

- Ensure manual override capability for RCIC suction transfer

GESSAR II
238 NUCLEAR ISLAND

ATTACHMENT A
TO
APPENDIX 15E

## ACRS QUESTIONS PERTAINING TO AC/DC POWER SYSTEM RELIABILITY

### 15EA.1 DC RELIABILITY

Question: The NRC Staff has issued a report (NUREG-0666) on the reliability of d.c. power system in which a 2-train d.c. system found to meet minimum NRC requirements was evaluated. As a result, the d.c. power system was identified as a potentially high contributor to core melt. The applicant could be asked what his assessment of his d.c. system is and what consideration he has given to the recommendations of NUREG-0666.

Response: We do not favor the use of such a minimum system as considered in NUREG-0666. [redacted] For example, it has a single bus tie breaker with too much potential for common cause failure. ~~Our~~ The original GESSAR II design allowed d.c. cross-connection capability with dual cross-tie breakers and double key interlocks. GE agreed to delete the d.c. cross-connection capability from the GESSAR II design until such time it can be shown that this capability does not contribute to d.c. system unreliability.

The following is provided in response to the recommendations in NUREG-0666:

(1) Prohibits certain design and operational features of the d.c. power system such as use of a tie breaker which could compromise divisional independence. As noted above, GESSAR II complies although we believe cross-connection capability is appropriate for specific conditions during shutdown and occurrences which require last resort flexibility (such as station blackout). GESSAR II has four

safety-related batteries, each of which has two chargers so that charger maintenance does not require use of cross-connections nor cause draw-down on the battery.

(2) Addresses testing and maintenance activities. These are accomplished by the applicant. We agree with these recommendations, and the GESSAR II design allows their implementation.

(3) Requires staggered test and maintenance activities to minimize the potential for human error related common cause failure. This is controlled in the field, but we agree that these actions are appropriate.

(4) Requires design and operational features to be adequate to maintain reactor core cooling in the hot standby condition following the loss of any one d.c. power bus and a single independent failure of any other system required for shutdown cooling. Although we cannot disagree with the intent of this recommendation, a judgment as to what features are needed should be tempered with an assessment of the reliability of the d.c. power loads and sources. We have concentrated on maintaining full separation and independence between division 1 and division 2 d.c. systems to provide this reliability. [redacted] With four independent d.c. systems and with three independent a.c. systems, the GESSAR II design shown ~~we expect~~ substantial capability in meeting the NUREG-0666 recommendation. For example, a potentially adverse capability loss would follow from the loss of both RHR systems, but the suppression pool can

store decay heat for several hours, during which it may be possible to recover active decay heat removal.

15EA.2 Grid Reliability

Question: What is the applicant's assessment of grid reliability and what procedures exist for restoring offsite power to the plant in the event of this loss.

Response: The grid is the responsibility of the applicant, and we assume he will meet the NRC requirements in this area. On loss of normal preferred offsite power, there is automatic transfer to the alternate offsite power source and, if necessary, to the onsite diesel generators. Restoring preferred power is accomplished manually by the control room operator. The specific procedures for restoration of power in the switchyard or transmission systems would be developed by the applicant.

Station Blackout Analysis

Question: What are the results of the applicant's station blackout analyses? Has the applicant made a best-estimate analysis of the accident sequence and evaluated what might be done to improve the plant, or has a conservative analysis been made with a core melt assumed after some specified degradation of the battery?

Response: This evaluation responds to both questions. [redacted] Our best-estimate analysis to the extent that it is complete is the primary subject of this supplement. We have identified potential system design and procedural improvements, and we will implement them upon concurrence from the NRC that they [redacted] satisfactorily resolve the issue.

[redacted] Our protabilistic risk assessment considered station blackout capability in a conservative manner (core cooling lost in two hours due to battery depletion and loss of RCIC control). We believe the more realistic treatment considering automatic and manual d.c. load shedding shows a substantially longer capability.

15EA.3 Diesel Generators

Question: What is the applicant's assessment of his diesel generator system? To what extent has LER and operating experiences been used to improve the design?

Response: Our HPCS diesel generator has undergone extensive testing (including 300 tests without failure) which has been documented for the NRC. From this testing and from field experience we have high confidence in the design. Extensive review of the design specifiation, the installation design and the auxiliary system design for the larger diesel generators (division 1 and 2) demonstrates [redacted] high availability from these units.

15EA.4 Low Power Testing/Simulated Loss of Offsite Power

Question: Has the applicant performed low power testing and a simulated loss of offsite power test? If so, what are the results and what has the applicant learned?

Response: [redacted]
This is the responsibility of the Applicant.
[redacted]

156.5.1.4

~~Area~~ Drywell

a. Reason for Concern

- o High drywell temperature could cause RPV level instrument reference leg boiloff.
- o High drywell temperature might exceed qualification levels for drywell equipment.
- o High drywell temperature could cause SRV solenoid failure.

b. Plant Response

Approx. 135°F during plant operation

<270°F prior to depressurization at 30 min.

<200°F after depressurization to 200 psi

Drywell equipment qualified for >300°F

Capability: unlimited

c. Assumed Operator Actions

- o Depressurization to approx. 200 psi to limit drywell heatup.
- o Maintain pressure >118 psi to avoid reference leg flooding.
- o Maintain RPV water level approx. + 20" on Enhanced Level Instrument.

d. Recommended Modifications/Actions

- o Enhanced water level instrument (ELI) compensates for drywell and containment temperature effects. (Previously recommended. See [redacted] Appendix 1D.)

15E.5.1.5

~~Area~~ Control Room

a. Reason for Concern

- High control room temperature could cause computer/microprocessor controls to fail.
- High temperature could make the control room uninhabitable.

b. Plant Response

| Capability: unlimited. |
|---|

- PGCC floor section heat sinks expected to prevent heatup above 105°F.
- Humidity could become uncomfortable but not uninhabitable.

Microprocessors (ELI, ERIS, etc.) unreliable above approx. 105°F but backup information is available at Remote Shutdown Station (RSS).

c. Assumed Operator Actions

- Transfer control to remote shutdown station (RSS) if control room becomes uninhabitable. (not expected)

d. Potential Modifications/Actions

None.

156.3.1.6

~~Area:~~ Fuel Pool

a. Reason for Concern

o Loss of fuel pool cooling could cause fuel pool to boil away.

b. Plant Response

o Approx. 14 hrs to boiling

o Approx. 77 hrs to fuel uncovery

Basis: Judgment probably longer with less hot fuel

Capability >75 hrs.

c. Assumed Operator Actions

None, but SRV air bottle replacement (see pneumatic supply) could be hampered by fuel building environment after approx. 14 hrs.

d. Potential Modifications/Actions

Consideration of moving extra air bottles to corridor outside fuel building. Not required for station blackout.

ISE.5.2 Energy Supplies

~~Energy Supply~~ ISE.5.2.1 Pneumatic Supply

a. Major Sources of Consumption

- o ADS/SRV
- o Drywell and containment vacuum breakers

b. Estimated Duration (5000 CF available)

SRV Depressurization approx. 50 actuations @ 8 CF/actuation = 400 CF

Ongoing SRV use approx. $\frac{1 \text{ actuation}}{2 \text{ min.}} \times \frac{60 \text{ min.}}{\text{hr.}} \times 8$ CF = 240 CFH

Leakage @ 1 CFH/valve x 8 valves = 8 CFH

DW Vacuum Breakers approx. $\frac{1 \text{ act}}{7 \text{ hrs}}$ @ $\frac{15 \text{ CF}}{\text{act}}$ x 2 VB = 4 CFH

total approx. 250 CFH

$\frac{5000 - 400}{250}$ = 18 hrs. $\boxed{\text{Capacity >18 hrs}}$

c. Operator Actions to Extend Duration

- o Air bottle replacement after depletion possible if necessary (not expected).
- o Rotate use of ADS/SRV valves to permit time for accumulators to recharge and give preference to Division 2 ADS/SRV values.
- o Monitor SRV position indication to indicate need for switch to other values (valves close when air supply lost).

d. Potential Modifications

None

15E.5.2.2

~~Energy Supply~~ 125 VDC - Bus E

a. Major Sources of Consumption

See Table 8.3-6

b. Estimated Duration (1950 amp hours (AH), 2 hr)

RCIC Gland Compressor Modification (see below) delete 58A

Shed load approx 35A (see below)

Steady state load approx. 251-58-35 = 158A

| Capability |
|---|
| > __*__ hrs. |

c. Operator Actions to Extend Duration

- Shed the following loads (at approx. 30 min.)
  - NMS panel H13-P669 (NSPS) - 25A from NSPS inverter
  - Emergency lighting (fuel building) - 10A

d. Potential Modifications

- Power RCIC gland compressor from an alternate source.
- Delete 125 VDC emergency lighting system except for control building or move to Bus J.
- Provide Emergency crosstie capability with dual crosstie breakers and double key interlocks if needed for longer duration.*
- Provide larger capacity battery if needed for longer duration*.

*The capability of this battery with load shedding is being evaluated. If the estimated duration is less than about 10 hours, the addition of crossties or expanded battery size will be reviewed to determine the optimum configuration for achieving a 10-hour capability.

15E.5.2.3

~~Energy Supply~~ 125 VDC - Bus F

a. Major Sources of Consumption

See Table 8.3-7

b. Estimated Duration (1500AH, 2hr)

Shed Loads approx. 40A (see below)
Steady State Load = 175 -40 = 135A

| |
|---|
| Capability<br>> * hrs. |

c. Operator Actions to Extend Duration

Shed the following loads at approx. 30 min.

- NMS panel H13-P670 (NSPS) -25A
- Emergency lighting -15A

d. Potential Modifications

- o Delete 125 VDC emergency lighting in auxiliary building
- o Provide larger capacity battery if needed for longer duration.*

*The capability of this battery with load shedding is being evaluated. If the estimated duration is less than about ~~8~~ 10 hours, the addition of crossties or expanded battery size will be reviewed to determine the optimum configuration for achieving a 10-hour capability.

156.5.2.4

~~Energy Supply~~ 125 VDC Bus G

Major Sources of Consumption

See Table 8.3-8

Estimated Duration (400 AH, 6 hr)

Shed Loads = 25A (see below)
SS load = 78 -25 = 53A

| Capability |
| --- |
| > * hrs. |

Operator Actions to Extend Duration

Shed the following load at approx. 30 min.

NMS panel H13-P671 (NSPS) -25A

Potential Modifications

Larger capacity battery if needed for longer duration.*

*The capability of this battery with load shedding is being evaluated. If the estimated duration is less than about ~~6~~ 10 hours, the addition of crossties or expanded battery size will be reviewed to determine the optimum configuration for achieving a 10-hour capability.

15E.5.2.5

~~Energy Supply~~ 125 VDC Bus H

Major Sources of Consumption

See Table 8.3-9

Estimated Duration (425 AH, 2 hr)

Load Shed = 25A
SS Load = 100 -25 = 75A

Capability
> _*_ hrs.

Operator Actions to Extend Duration

Shed the following load at approx. 30 min.
Shed NMS Panel H13-P672 (NSPS) -25A

Potential Modifications

None

*The capability of this battery with load shedding is being evaluated. If the estimated duration is less than about [redacted] 10 hours, the addition of crossties or expanded battery size will be reviewed to determine the optimum configuration for achieving a 10-hour capability.

TABLE ~~##~~ 15E-1

VARIABLES ASSESSED FOR STATION BLACKOUT ASSESSMENT

| Variable | RG 1.97 Type | RG 1.97 Category | Discussion Subsection | Needed in Black-out Sequence? |
|---|---|---|---|---|
| Reactivity Control | | | | |
| Neutron Flux (value, rate, trend) | A,B | 1 | 1D.2.3.1 | No* |
| Control Rod Position | B | 3 | 1D.2.3.2 | No* |
| Boron Concentration (sample) | B | 3 | 1D.2.3.3 | No |
| Core Cooling | | | | |
| Coolant Level in the Reactor (value, trend) | A,B,C | 1 | 1D.2.3.4 | Yes |
| Maintaining Reactor Coolant System Integrity | | | | |
| RCS Pressure (value + alarm) | A,B,C | 1 | 1D,2.3.5 | Yes |
| Drywell Sump Level (value + alarm) | B,C | 3 | 1D.2.3.6 | No |
| Drywell Pressure | B,C,D | 1,2 | 1D.2.3.7 | No |
| Primary Containment Area Radiation | E<br>C | 1<br>3 | 1D.2.3.8 | No |
| Suppression Pool Water Level | A,C,D | 1.2 | 1D.2.3.9 | Yes |
| Maintaining Containment Integrity | | | | |
| Primary Containment Isolation Valve Position (Excluding Check Valves) | B | 1 | 1D.2.3.10 | Yes** |
| Primary Containment Temperature | A | 1 | 1D.2.3.11 | Yes |

*ATWS plus blackout is not considered in this study. Failure to scram can be inferred from abnormal water level and pressure response.

**Plus RCIC minimum flow.

TABLE ~~4-1~~ 15E-1

VARIABLES ASSESSED FOR STATION BLACKOUT ASSESSMENT (Continued)

| Variable | RG 1.97 Type | RG 1.97 Category | Discussion Subsection | Needed in Blackout Sequence? |
|---|---|---|---|---|
| **Maintaining Containment Integrity (Continued** | | | | |
| Primary Containment Pressure (value, rate, trend, + alarm) | A,B,C | 1 | 1D.2.3.12 | Yes |
| Drywell/Containment Hydrogen Concentration (value) | A,C | 1 | 1D.2.3.13 | No |
| Secondary Containment Area Radiation (value) | C,E | 2 | 1D.2.3.14 | No |
| Secondary Containment Noble Gas Effluent | C,E | 2 | 1D.2.3.15 | No |
| Primary Containment Noble Gas Effluent | C | 3 | 1D.2.3.16 | No |
| Suppression Pool Temperature | A,D | 1,2 | 1D.2.3.17 | Yes |
| Drywell Air Temperature | A,D | 1,2 | 1D.2.3.18 | Yes |
| **Fuel Cladding Barrier Monitoring** | | | | |
| Coolant Radiation (value + alarm) | N/A | N/A | 1D.2.3.19 | - |
| Coolant Gamma (1 sample/6 hours) results within 72 hr | C | 3 | 1D.2.3.20 | No |
| **System Operation** | | | | |
| Main Steam Line Isolation Valve Leakage Control System Pressure | D | 2 | 1D.2.3.21 | No |
| Containment Spray Flow | D | 2 | 1D.2.3.22 | No |

TABLE ~~1D~~ 15E-1

VARIABLES ASSESSED FOR STATION BLACKOUT ASSESSMENT (Continued)

| Variable | RG 1.97 Type | RG 1.97 Category | Discussion Subsection | Needed in Black-out Sequence? |
|---|---|---|---|---|
| **System Operation (Continued)** | | | | |
| Residual Heat Removal (RHR) System Flow | D | 2 | 1D.2.3.22 | No |
| RHR Service Water Flow | D | 2 | 1D.2.3.23 | No |
| Low Pressure Coolant Injection System Flow | D | 2 | 1D.2.3.22 | No |
| Reactor Core Isolation Cooling System Flow | D | 2 | 1D.2.3.24 | Yes |
| RCIC Room Temp. | - | - | - | Yes |
| Control Room Temp. | - | - | - | Yes |
| High Pressure Coolant Spray System Flow | D | 2 | 1D.2.3.24 | No |
| Core Spray System Flow | D | 2 | 1D.2.3.24 | No |
| Standby Liquid Control System (SLCS) Flow | D | 2 | 1D.2.3.25 | No |
| SLCS Storage Tank Level | D | 3 | 1D.2.3.26 | No |
| SRV Position | D | 2 | 1D.2.3.27 | Yes |
| Feedwater Flow | D | 3 | 1D.2.3.28 | No |
| CST Level | D | 3 | 1D.2.3.29 | Yes |
| ESF Cooling Water Flow | D | 2 | 1D.2.3.30 | No |
| ESF Cooling Water Temperature | D | 2 | 1D.2.3.30 | No |
| High Radioactivity Tank Level | D | 3 | 1D.2.3.31 | No |
| Emergency Vent Damper Position | D | 2 | 1D.2.3.32 | Yes |
| Standby Energy Status | D | 2 | 1D.2.3.33 | Yes* |

*Including breaker position.

TABLE ~~4~~ 15E-1

VARIABLES ASSESSED FOR STATION BLACKOUT ASSESSMENT (Continued)

| Variable | RG 1.97 Type | RG 1.97 Category | Discussion Subsection | Needed in Blackout Sequence? |
|---|---|---|---|---|
| Effluent Monitoring | | | | |
| SGTS Ventilation Flow Rate | E | 2 | 1D.2.3.34 | No |
| Other Ventilation Flow Rates | E | 3 | 1D.2.3.34 | No |
| Particulate/Halogen Release (sample) | E | 3 | 1D.2.3.35 | No |
| Environs Radioactivity Monitoring | E | 3 | 1D.2.3.36 | No |
| Meteorology | E | 3 | 1D.2.3.37 | No |
| Post-Accident Sampling (sample) | E | 3 | 1D.2.3.38 | No |

TABLE 15E-2

POWER SUPPLIES TO INSTRUMENTS NEEDED FOR A BLACKOUT

| Variable | Control Room Indicator | Power Supply | Available? | Notes |
|---|---|---|---|---|
| RPV Level | B21 R623A<br>R623B | 120 Inst. Bus A<br>120 Inst. Bus B | Yes | 1 |
| RPV Pressure | B21 R623A<br>R623B | 120 Inst. Bus A<br>120 Inst. Bus B | Yes<br>Yes | 1<br>1 |
| Suppression Pool Water Level | P50-R600A,B | 125 VDC | Yes | 3 |
| Pri. Containment Isol. Valve Position | Indication Lights | RPS | Yes | |
| Pri. Containment Temperature | T41-RR613A,B | 125 VDC | Yes | 3 |
| Pri. Containment Pressure | T41-RR618A,B | 125 VDC | Yes | 3 |
| Suppression Pool Temperature | P50-R600A,B | 125 VDC | Yes | 3 |
| Drywell Air Temperature | T41-RR611A,B | 125 VDC | Yes | 3 |
| RCIC Flow | E51-R606 | RPS | Yes | |
| RCIC Room Temperature | E31-R608 | RPS | Yes | |
| Control Room Temperature | - | - | Yes | 5 |
| SRV Position | Indicating Lights | 125 VDC | Yes | |
| CST Level | By applicant | By applicant | Yes | 2 |
| Emergency Vent Damper Position | Indicating Lights | 125 VDC | Yes | 3 |
| Standby Energy Status 619 kv AC | Voltmeters | Source | Yes | |
| DC | Voltmeters | Source | Yes | |
| Air | P53-R606A,B | 125 VDC | Yes | 3 |

Notes to Table ~~1-2~~ 15E-2

1. Enhanced Water Level Instrument to be powered from d.c. power.

2. D.C. power to be provided by applicant.

3. Power Supply from 125V d.c. to Reactor Island Logic Panels P881 or P882.

4. Exhaust air measurement may be unreliable. Local thermometer to be supplied by applicant.

GESSAR II
238 NUCLEAR ISLAND

ATTACHMENT B
TO
APPENDIX 15E

# RCIC ROOM HEATUP DURING A STATION BLACKOUT

## 15EB.1 PURPOSE

The purpose of this ~~memorandum~~ attachment is to document the results of analysis performed by Containment and Radiological Engineering on Reactor Core Isolation Cooling System (RCIC) room temperature response during a station blackout for ~~the~~ GESSAR ~~standard~~ II. ~~plant.~~ The results indicate that a station blackout imposes no threat to the operation of RCIC with the RCIC room temperature reaching 122°F 12 hours into the transient, well below the point above which RCIC performance would be degraded. Sensitivity results for some of the most important parameters are also given.

## 15EB.2 INTRODUCTION

A station blackout results in loss of all A.C. power (both offsite and onsite sources), initiating reactor isolation and scram. For this analysis all three diesel generators of a BWR plant are assumed inoperative, i.e., no Emergency Core Cooling System (ECCS) pumps are available: this leaves the battery operated RCIC as the only system available for core cooling. Thus, it is essential that the RCIC remains operational. An important requirement for the proper functioning of the RCIC is that the RCIC room temperature be maintained below the equipment operational limit.

The loss of all A.C. power also means the loss of lighting, auxiliary equipment operation, area HVAC and drywell fan coolers, resulting in a drywell heatup. At some point reactor depressurization will be initiated to reduce the heat input to the drywell, although the reactor is assumed to be depressurized only to the point sufficiently above the RCIC shutoff pressure so that operation of the RCIC can be maintained.

RCIC initially draws water from the Condensate Storage Tank (CST). However, an automatic switchover to the suppression pool as the water

source would occur if the CST water level drops too low or the suppression pool water level rises above a certain point. Since the suppression pool heats up as a result of SRV discharges and subsequent reactor depressurization, and since the design temperature for the RCIC pump is 140°F, a manual switch back to the CST from the suppression pool as the RCIC water source is required when the pool temperature approaches 140°F. Since the time period when the RCIC takes suction from the suppression pool is relatively short (about 30 minutes) compared to the transient period of interest (up to 20 hours), the impact on RCIC room temperature in assuming that RCIC draws all water from the CST is insignificant.

E8.3

MODELING AND ASSUMPTIONS

To model the RCIC room temperature response, thermodynamic properties of steam and air in the room are evaluated based on mass and energy balances. Heat sources and heat sinks were considered. In addition, some steam has leaked into the room through the RCIC turbine gland seal. The room is conservatively assumed to be isolated from the adjacent rooms.

Heat Sources - The following heat sources are modeled:

- Steam Pipes - there is a six inch steam pipe upstream of the RCIC turbine, 60 ft long, with three inches of insulation, with the pipe temperature assumed equal to the reactor steam temperature of 552°F under normal operating conditions, and 388°F after reactor depressurization to 200 psig): and a sixteen inch exhaust steam pipe downstream of the RCIC turbine, 40 ft long, with two inches of insulation, with pipe temperature at 250°F because steam pressure downstream of the turbine is held at 25 psia.

- Water Pipes - two uninsulated water pipes, one suction pipe and the other discharge pipe, with dimensions of 8''X 38 ft and 6''X 36 ft, carry water from the water source and inject it into the reactor. As mentioned previously, the water source may be either the CST or the suppression pool, thus the water temperature may vary from the CST temperature of 90°F up to the suppression pool temperature. Depending on the RCIC room temperature at a particular time, these water pipes may be either heat sources or heat sinks.

- Turbine - the RCIC turbine is insulated. The turbine temperature is taken as the average upstream and downstream steam temperatures. Small portions of turbine that are not insulated are not modeled.

- RCIC Pump - the RCIC pump weighs 6600 lbm and is not insulated. As in the case of water pipes, the RCIC pump may become a heat sink depending on the room temperature and the water temperature.

Heat Sinks - The following heat sinks are modeled:

- Concrete Walls, Floor and Ceiling - the walls are 26 ft tall, with widths varying from 18 ft to 31 ft. Thicknesses vary from 1 ft to 3 ft. These structures were conservatively assumed to be insulated on the outer surface.

- Turbine Base Plate - it weighs 900 lbm and is uninsulated.

- Room Cooler - it weighs 2000 lbm and is uninsulated.

- As mentioned previously, the water pipes and RCIC pump become heat sinks if the RCIC room temperature is higher than the RCIC water temperature.

Analytical Assumptions - The following assumptions were made in the analysis, with justifications for these assumptions given subsequently:

- Air and steam are uniformly mixed at all times.

- Air behaves lik an ideal gas.

- No condensation on structural surfaces.

- The RCIC room is isolated from the surroundings.

- Heat conduction is one dimensional through structures and walls.

Since the period of interest is several hours, steam leaked into the room has sufficient time to diffuse and mix with air, therefore, the uniform mixing assumption is a good approximation. Also, since only low pressures and temperatures are encountered, the ideal gas law holds true for air.

Assumptions of no condensation on structural surfaces is conservative because the free-convection heat transfer coefficient used in the absence of condensation is smaller than the condensing heat transfer coefficient. Isolating the RCIC room is another conservatism, because mass and energy are preventd from leaving the room through conduction, convection and radiation. Finally, the one-dimensional heat conduction assumption is correct excepc at the corners of the walls, but the impact is negligible.

5B.4

INPUT PARAMETERS

The following initial conditions and key parameters were used in the analysis:

- Initial room temperature was 90°F.

- Steam leakage rate was 70 lbm/hr.

- No reactor depressurization for the first 30 inutes (as the operator is trying to determine a··opriate actions) and the reactor was cooled down at 100°F/hr.

- Temperature of RCIC water was 90°F, which is the technical specification CST temperature, because the RCIC can take suction from the suppression pool for only a short period of time and the operator will switch the sucton back to the CST as the pool approaches 140°F.

5EB.5
## RESULTS AND DISCUSSIONS

A timeshare computer program has been developed to carry out the calculations described above.

The RCIC room temperature response following a station blackout is given in Figure 15EB-1. ~~1.~~ The temperature increases rapidly during the first hour of the transient, then the rate of increase levels off subsequently. The room temperature rises to 119°F at eight hours of transient and 122°F at twelve hours of transient.

Figures 15EB-2 and 15EB-3 ~~2 and 3~~ show the sensitivity results at high water temperature and low steam leakage rate, respectively. With the water temperature at 140°F, the RCIC room temperature rises to 133°F at twelve hours, while at the steam leakage rate of 10 lbm/hr (which corresponds to new turbine gland seal condition) the room temperature reaches only 101°F at twelve hours. The high sensitivity to the steam leakage rate is due to the large latent heat of steam which is released upon condensing in the RCIC room. The sensitivity study also indicates that there is no impact of reactor cooldown rate on the RCIC room temperature response.

The above results indicate that the RCIC room temperature twelve hours following a station blackout to be substantially below the equipment quaification limits of 212°F for the first six hours and 150°F between six and twelve hours following a station blackout. This shows that proper operation of the RCIC can be maintained for many hours during a station blackout to provide adequate core cooling.

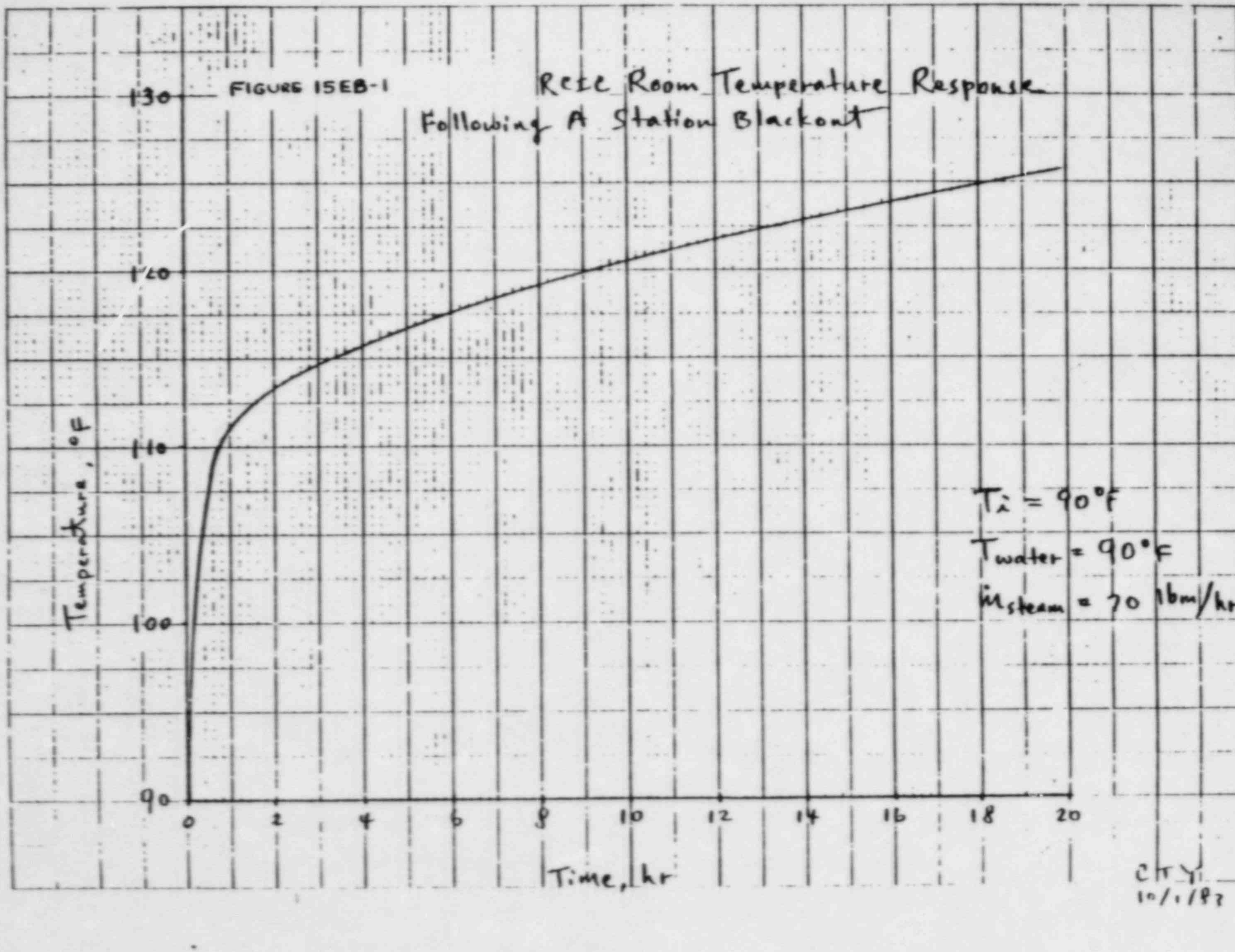


FIGURE 15EB-1
RCIC Room Temperature Response
Following A Station Blackout
Temperature, °F
130
120
110
100
90
0
2
4
6
8
10
12
14
16
18
20
Time, hr
$T_i = 90°F$
$T_{water} = 90°F$
$\dot{m}_{steam} = 70$ lbm/hr
CTY
10/1/83

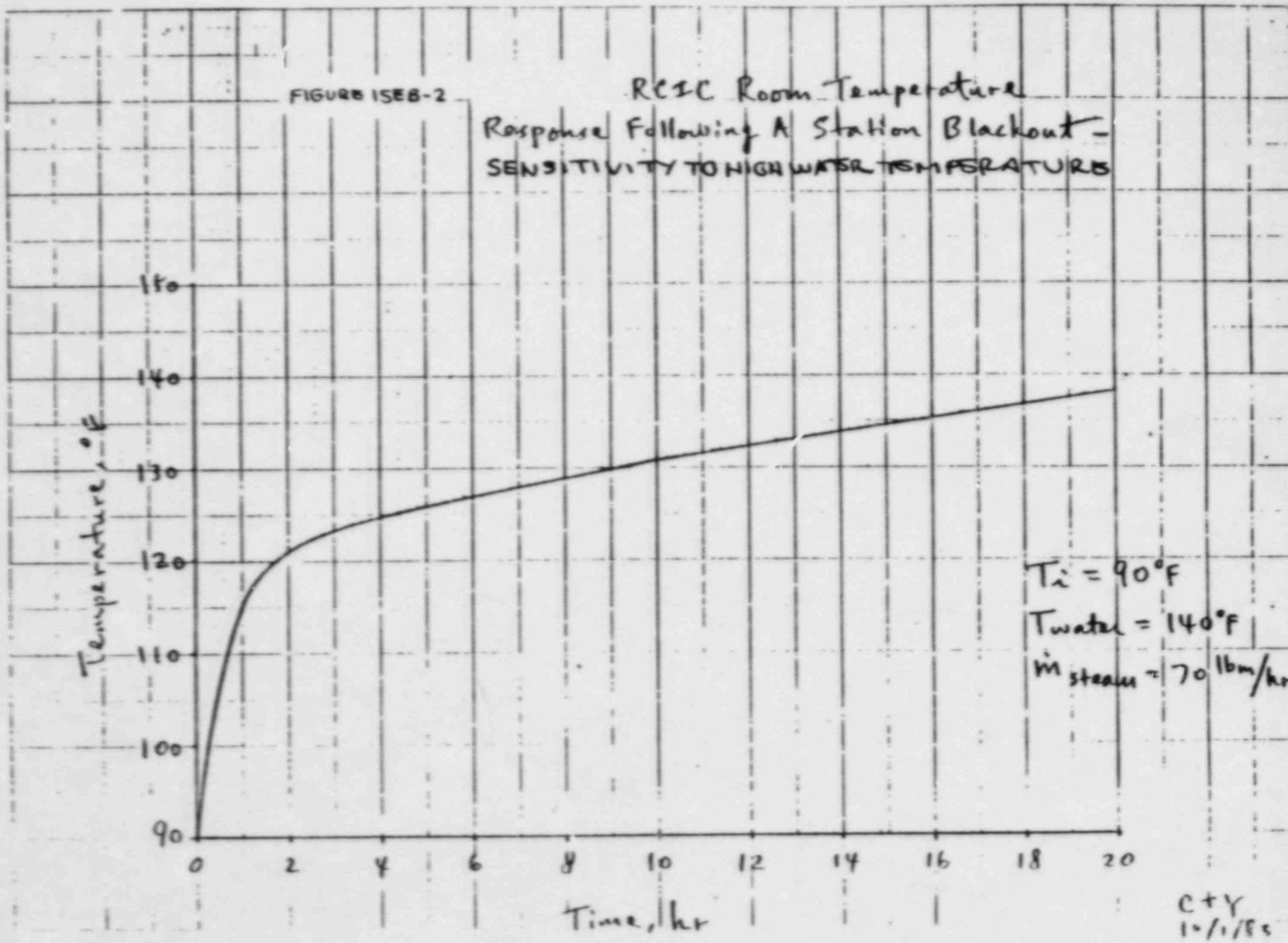
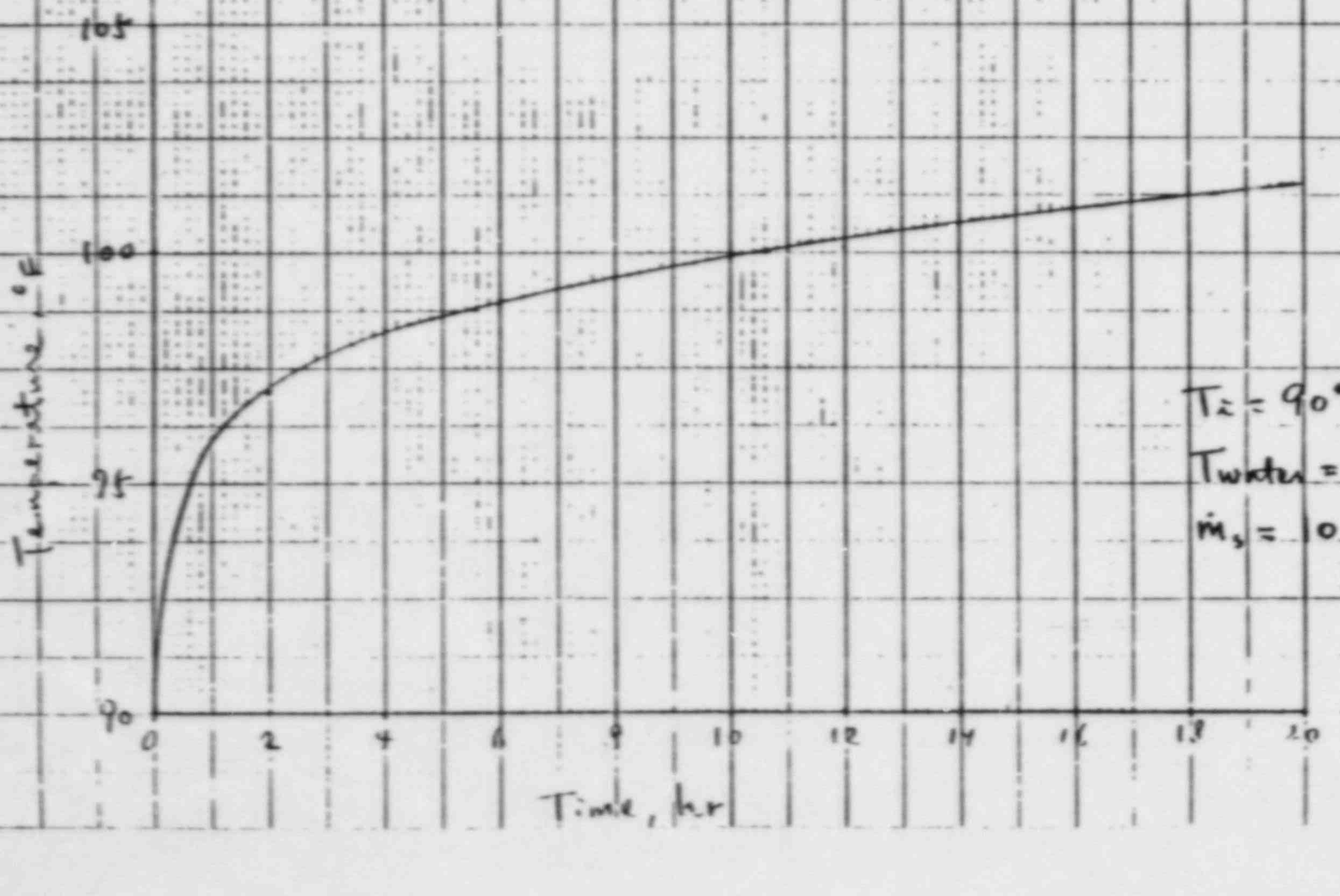


FIGURE ISEB-2
RCIC Room Temperature
Response Following A Station Blackout –
SENSITIVITY TO HIGH WATER TEMPERATURE
Temperature, °F
150
140
130
120
110
100
90
0
2
4
6
8
10
12
14
16
18
20
Time, hr
$T_i$ = 90°F
$T_{water}$ = 140°F
$\dot{m}_{steam}$ = 70 lbm/hr
C+Y
10/1/85

FIGURE 15BB-3. RCIC Room Temperature Response Following A Station Blackout – SENSITIVITY TO LOW STEAM LEAKAGE RATE




CTY
10/1/85