The Light company
Houston Lighting & Power

South Texas Project Electric Generating Station   P. O. Box 289   Wadsworth, Texas 77483

March 1, 1990
ST-HL-AE-3380
File No.: G20.1
10CFR50.12

U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555

South Texas Project Electric Generating Station
Units 1 & 2
Docket Nos. STN 50-498, STN 50-499
Responses to the
Requests for Additional Information from
Sandia National Laboratory

Reference: Letter from Sandia National Laboratory
to the U.S. Nuclear Regulatory Commission
dated January 3,1990

Enclosed are responses to questions raised by Sandia National Laboratory (SNL) during their review of the South Texas Project Electric Generating Station (STPEGS) Probabilistic Safety Assessment (PSA). The Question A.4 response (Attachment 1) related to steam generator dryout completes the action items resulting from the November 28-30, 1989 plant visit. The responses to questions Q1 and Q2, received in the above referenced letter, regarding the STPEGS PSA fire analysis are included as Attachment 2.

If you should have any questions on this matter, or the attachments, please contact Mr. A. W. Harrison at (512) 972-7298 or myself at (512) 972-8530.

M A McBurnett

M. A. McBurnett
Manager
Licensing

MAM/sdp

ATTACHMENTS: (1) Response to Question A.4, regarding Steam Generator dry out

(2) Response to Questions Q1 and Q2, regarding the STPEGS PSA

SAM-PRA3

A021
1/1

cc:

Regional Administrator, Region IV
Nuclear Regulatory Commission
611 Ryan Plaza Drive, Suite 1000
Arlington, TX 76011

George Dick, Project Manager
U.S. Nuclear Regulatory Commission
Washington, DC 20555

J. I. Tapia
Senior Resident Inspector
c/o U. S. Nuclear Regulatory
Commission
P. O. Box 910
Bay City, TX 77414

J. R. Newman, Esquire
Newman & Holtzinger, P.C.
1615 L Street, N.W.
Washington, DC 20036

D. E. Ward/R. P. Verret
Central Power & Light Company
P. O. Box 2121
Corpus Christi, TX 78403

J. C. Lanier
Director of Generation
City of Austin Electric Utility
721 Barton Springs Road
Austin, TX 78704

R. J. Costello/M. T. Hardt
City Public Service Board
P. O. Box 1771
San Antonio, TX 78296

Rufus S. Scott
Associate General Counsel
Houston Lighting & Power Company
P. O. Box 61867
Houston, TX 77208

INPO
Records Center
1100 Circle 75 Parkway
Atlanta, GA 30339-3064

Dr. Joseph M. Hendrie
50 Bellport Lane
Bellport, NY 11713

D. K. Lacker
Bureau of Radiation Control
Texas Department of Health
1100 West 49th Street
Austin, TX 78704

Revised 12/15/89

L4/NRC/

ATTACHMENT 1

Question A.4. from the November 28-30, 1989 SNL Site Visit

Section B.1 HEOB02 estimates that over one hour is required for steam generator dryout following reactor and turbine trip with no feedwater. This section assumes the reactor trips on low-low steam generator level "...estimated to be about 90% of the normal full-power liquid inventory." The FSAR Figures 15.2.9A and 15.2-10 indicate that the secondary mass in each steam generator is about 60,000 lbm at low-low level trip which is less than 50% of the full power inventory. Using this lower inventory, dryout is estimated to occur at about 30 minutes.

A.4.1: What is the justification for the 90% assumption?

A.4.2 How does a decrease in time to dryout from one hour to 30 minutes affect the PSA model?

A.4.3 Is the discrepancy due to the fact that level is calculated by measuring the pressure drop across two taps in the downcomer and flow losses are much less without feedwater?

HL&P Response:

A.4.1

The 90% of nominal inventory was based on the Seabrook plant.[1] The STPEGS FSAR value of approximately 60,000 (lbm) is conservative based on instrumentation errors. The STPEGS nominal operating steam generator level is 59% on the narrow range span, which corresponds to a calculated best-estimate liquid water mass of approximately 487,538 (lbm) for all four steam generators per Reference 2. The low-low steam generator level setpoint is 33% on the narrow range. Reference 2 calculated the corresponding best-estimate liquid water mass to be approximately 362,063 (lbm) for all four steam generators, which is approximately 74% of the nominal and not 90%. Thus, the assumption, as stated, is not conservative and the PSA calculation has been revised, as shown on the marked-up pages attached, to yield a dryout time of 48 minutes versus 84 minutes.

A.4.2

HEOB02 represents the likelihood of the operators failing to initiate primary side "bleed and feed" prior to steam generator dryout given the loss of main feedwater and the failure of auxiliary feedwater. This scenario assumes reactor trip occurs due to low-low steam generator level, which relates to a secondary side inventory of about 74% of the nominal as identified above in Response A.4.1.

Given this scenario, STPEGS reactor operators may enter several emergency operating procedures (EOPs) in response to the reactor trip and before initiating "bleed and feed". The first EOP is 0POP05-EO-EO00, Reactor Trip or Safety Injection, which determines whether safety injection is required or not. If SI is not required (e.g., loss of main feedwater initiating event), then step 4.0 would lead the operators to 0POP05-EO-ES01, Reactor Trip Response, and to 0POP05-EO-FRH1, Response to Loss of Secondary Heat Sink, when inadequate feed flow is identified. If SI is required (e.g., main feedwater line break initiating event), then step 19.0 would lead the operators directly to 0POP05-EO-FRH1, Response to Loss of Secondary Heat Sink.

0POP05-EO-FRH1 directs the operators to trip the reactor coolant pumps (RCPs) and initiate "bleed and feed" immediately when certain conditions exist (i.e., wide range level less than 37% <u>or</u> pressurizer pressure greater than 2335 psig). Assuming these conditions have not yet been met, the operators are directed to reestablish the secondary heat sink. This activity includes troubleshooting the auxiliary feedwater, motor-driven startup feedwater, steam-driven feedwater, and condensate flow paths. Note that the operators are continually monitoring the critical safety funtions and are procedurally required to initiate "bleed and feed" when the criteria stated above is met.

The Westinghouse Owners Group (WOG) emergency response guidelines (ERGs) identify that a best estimate expectation of when the operator can be expected to trip the RCPs following reactor trip is approximately 5 minutes.[6] This elapsed time can correspond to either having just entered 0POP05-EO-FRH1 (i.e., the conditions have been met to trip RCPs and initiate "bleed and feed") or reached Step 3.0 of 0POP05-EO-FRH1, Stop all RCPs. To be conservative, the operators will know within 15 minutes after reactor trip to initiate "bleed and feed". Approximately 3 minutes is required to initiate "bleed and feed".

In confirmation of the the above procedural guidance, a review of the operator survey results (i.e., Table 15.4-39 of Reference 3) showed that the operators gave the "time" performance shaping factor (PSF) the lowest rating (or importance) of the seven factors included in the survey. The most important factors from the operator's view were "stress" and "procedures", as shown on the attached markup of Table 15.4-39. "Time" was not a factor to the operators with respect to this scenario; thus the procedure used to quantify human error rates (HERs) for the PSA would not be impacted by the change. Section 15.2 of Reference 3 provides a more detailed discussion of the procedure used to quantify HERs (e.g., HEOB02) and the role PSFs play in this process. Therefore, a dryout time of 48 minutes will have no impact on the value of HEOB02.

A review of the dominant sequences leading to core damage as predicted by the PSA (i.e., Table 2.1-3 of Reference 3) shows that the most likely initiating event resulting in loss of secondary heat sink is the loss of offsite power (LOSP). For a LOSP initiating event resulting in station blackout, the reactor, turbine, and reactor coolant pumps would trip at time zero, thus resulting in the entire nominal steam generator water mass available for decay heat removal and more time for recovery actions. These recovery actions include getting the turbine-driven auxiliary feedwater pump started and/or restoring electric power prior to steam generator dryout.

HL&P calculated a range of dryout times for the STPEGS steam generators under various initiating events and assumptions.[2,4] For the LOSP case, the range of dryout times is from 64 to 72 minutes. Note that this range covers a span of 8 minutes based on different decay heat curves and conservative assumptions.

A.4.3

See response to Question A.4.1.

References

1. Pickard, Lowe, and Garrick, Inc. "Thermal-hydraulic Analysis of Postulated Loss of Decay Heat Removal Events During Shutdown," prepared for Public Service of New Hampshire. PLG-0595. December 1987.

2. Engineering Calculation: Time to Boil Steam Generators Dry with Loss of Feedwater. NE-TF-89-09-00. Houston Lighting & Power Company. January 1990.

3. Pickard, Lowe, and Garrick, Inc. "South Texas Project Probabilistic Safety Assessment," prepared for Houston Lighting & Power Company. PLG-0675. May 1989.

4. Engineering Calculation: Steam Generator Dryout Time for Station Blackout with Loss of Feedwater. NE-PA-90-01-00. Houston Lighting & Power Company. February 1990.

5. Larson, J.R. System Analysis Handbook. Prepared for the U.S. NRC by EG&G. NUREG/CR-4041. December 1984.

6. Westinghouse Owners Group Emergency Response Guidelines, Low Pressure Version. Revision 1. Background Volume FR-H. Prepared by Westinghouse Electric Corporation for The Westinghouse Owners Group. September 1, 1983.

Table 15.4-39. Grouping of HERs by Similar Average Weights

HER	TS	I/PI	Time	P/C ACT	PROC	TRN/EXP	Stress
HEOD03	0.12	0.12	0.17	0.12	0.14	0.14	0.18
HEOR08	0.14	0.17	0.16	0.11	0.16	0.16	0.10
HEOR07	0.13	0.18	0.15	0.12	0.16	0.16	0.10
HESL1	0.12	0.13	0.12	0.15	0.18	0.19	0.10
HEOR05	0.14	0.14	0.18	0.15	0.10	0.15	0.13
Average	0.13	0.15	0.16	0.13	0.15	0.16	0.12
HEOD02	0.08	0.18	0.08	0.20	0.18	0.16	0.12
HEOC01	0.16	0.12	0.07	0.17	0.21	0.16	0.12
HEOC02	0.16	0.14	0.06	0.14	0.22	0.16	0.14
HEOB04	0.09	0.14	0.04	0.19	0.17	0.16	0.20
HECH02	0.09	0.17	0.16	0.20	0.06	0.14	0.17
HEOB03	0.08	0.14	0.11	0.15	0.19	0.12	0.21
Average	0.12	0.14	0.09	0.17	0.17	0.15	0.17
HECH01	0.12	0.24	0.08	0.25	0.04	0.20	0.08
HEOR03	0.14	0.21	0.09	0.17	0.09	0.21	0.10
HEOR01	0.13	0.21	0.10	0.17	0.06	0.19	0.13
HEOR04	0.14	0.21	0.09	0.17	0.09	0.21	0.10
HEOR02	0.13	0.20	0.11	0.19	0.06	0.19	0.13
Average	0.13	0.21	0.09	0.19	0.07	0.20	0.11
HEOT02	0.11	0.20	0.11	0.13	0.13	0.20	0.11
HEOT01	0.12	0.20	0.10	0.13	0.13	0.20	0.12
HEOT03	0.11	0.19	0.11	0.13	0.13	0.19	0.13
HEOL02	0.11	0.19	0.08	0.17	0.17	0.16	0.13
HEOD01	0.14	0.19	0.09	0.10	0.17	0.19	0.13
HEOL01	0.11	0.19	0.10	0.17	0.17	0.13	0.13
Average	0.12	0.19	0.10	0.14	0.15	0.17	0.13
HEOS02	0.17	0.17	0.24	0.17	0.07	0.11	0.07
HEOS03	0.15	0.15	0.23	0.21	0.06	0.10	0.11
HEOS01	0.18	0.18	0.20	0.18	0.08	0.12	0.08
Average	0.17	0.17	0.22	0.19	0.07	0.11	0.09
HEOB02	0.09	0.14	0.09	0.13	0.20	0.14	0.21
HEOB07	0.08	0.13	0.13	0.14	0.17	0.13	0.21
HEOB09	0.08	0.15	0.11	0.14	0.17	0.14	0.20
HEOBA	0.08	0.16	0.14	0.15	0.18	0.10	0.19
HEOB06	0.09	0.14	0.14	0.12	0.19	0.14	0.19
Average	0.08	0.14	0.12	0.14	0.18	0.13	0.20

Lowest Rated PSFs for HEOB02

Highest Rated PSFs for HEOB02

APPENDIX B. THERMAL HYDRAULIC ANALYSES FOR HUMAN ACTION ACCIDENT SCENARIOS

The purpose of this appendix is to present simplified thermal hydraulic analyses to provide time windows for the human actions analysis scenarios that appear in the overall event sequence models. The analyses, in general, are based on first principle energy and mass balance considerations, and are used to evaluate factors such as times available for operator action and if safety injection can be initiated before the core uncovers. There are also some times approximated from the Westinghouse "Anticipated Transients Without Trip Analysis" (Reference B-1). All steam and fluid properties were determined from Reference B-2. Because of the simplifying assumptions implicit in the analyses, the results should be considered as reasonable approximations of the time windows that could impact operator actions and decisions. Results from more "detailed" computer calculations should be used for purposes requiring greater accuracy.

The human actions included as top events in the STP event tree models are identified by a six-character designator. The first two characters are "HE," representing human error. The next two characters identify the human action category as follows:

- OB — Operator Establishes Bleed and Feed Operation
- OC — Operator Initiates Closed Loop RHR Cooling
- OD — Operator Cools Down and Depressurizes the RCS
- ON — Operator Maintains Long-Term Steady State Operation
- OR — Operator Manually Starts Selected Equipment
- OS — Operator Establishes Ventilation
- OT — Operator Manually Trips the Reactor
- OCH — Operator Initiates RCS Makeup

The last two characters are numbers that are specific to the accident scenario in question.

Many of the time windows for the scenarios result in nearly the same sequences of events and, thus, the mass and energy calculations are conservatively considered the same, whenever appropriate. The results of the analyses and the time windows assigned to the human action scenarios are summarized in Table B-1. The order in which each analysis is presented in this appendix appears to be haphazard, but in reality is based on the order that the actual calculations were performed, as some analyses logically follow others as they rely on information calculated in previous analyses. The documentation of the calculations performed for scenario time windows or a discussion of rationale for the time windows assumed for the scenarios is presented in Sections B.1 through B.26.

Table B-1 (Page 1 of 3). Summary of Time Windows for Human Actions Scenarios			
Human Action Scenario	**Time Window for Operator Action**	**Subsection for Description of Analysis**	**Comments**
HEOB02	~~∼1 hour,~~ 48 ~~24~~ minutes	B.1	Estimated time calculated for steam generator dryout.
HEOB01		B.8	No estimate required; failure rate of 1.0 used because of the very low frequency of occurrence.
HEOB03	~~∼1 hour,~~ 48 ~~24~~ minutes	B.9	Time window is considered to be the same as for HEOB02.
HEOB04	t > 12 hours	B.4	Time window is calculated.
HEOB05		B.10	Not estimated; failure rate of 1.0 used because of very low frequency of occurrence.
HEOB06	~~∼1 hour,~~ 48 ~~24~~ minutes	B.11	Time window is considered to be the same as for HEOB02.
HEOB07	~~∼1 hour,~~ 48 ~~24~~ minutes	B.12	Time window is considered to be the same as for HEOB03.
HEOB08		B.13	Not estimated; failure rate of 1.0 used because of very low frequency of occurrence.
HEOBA	~~∼1 hour,~~ 48 ~~24~~ minutes	B.14	Time window is considered to be the same as for HEOB03.
HEOB09	~~∼1 hour,~~ 48 ~~24~~ minutes	B.15	Time window is considered to be the same as for HEOB02.
HEOCH01	16 minutes	B.2	Time window is calculated.
HEOCH02	∼ 5 minutes - low level ∼ 7 minutes - pressure low	B.3	Time windows are calculated.
Note: N/A = not applicable.			

B.1 HEOB02 — TIME FOR OPERATOR TO PERFORM BLEED AND FEED WHEN THE REACTOR AND TURBINE HAVE TRIPPED, MFW HAS BEEN LOST, AND THE AFW IS NOT AVAILABLE

Many of the accident sequences and human action scenarios analyzed in Section 15 involve cases wherein the reactor is tripped and the core is cooled by the steam generators, but no feedwater or steam generator PORVs are available. In such cases, the steam generator shell (secondary)-side water level will gradually drop and, eventually, steam generator dryout will occur. The intent of this analysis was to estimate how much time is available before steam generator dryout would be expected since this time is informative for a number of human action scenarios with regard to certain operator actions or equipment recovery.

At full power operation (3,800 MWt) with the steam generator level at the nominal value, each of the four steam generators has a shell-side ~~liquid~~ fluid inventory, 136,135 lb_m (Reference B-3). The total shell-side free volume of each steam generator is 7,985 ft^2 (Reference B-3). The steam generators provide steam at normal pressure of 1,085 psig and have safety relief valves set at 1,285 psig.

This analysis conservatively calculated the time for reactor decay heat to provide sufficient energy to the steam generators to raise the steam generator pressure from 1,085 psig to the relief pressure valve of 1,285 psig, and to convert the liquid inventory from saturated water at 1,085 psig to steam at 1,285 psig. The rate of heat transfer to the steam generators is taken to be that of the decay heat because the temperature difference will remain about constant between the primary and secondary coolants. Also, even if the rate of heat transfer is initially higher due to the stored energy in primary metallic components, the energy required will eventually balance out to that provided by the decay heat when the temperatures equilibrate.

However, the steam generator secondary temperature will actually increase about 21°F to that of the saturation temperature at the SRV pressure (1,285 psig), rather than remain at the normal operating pressure of 1,085 psig. Therefore, the time to boil the steam generator dry is calculated conservatively less by not accounting for this lower temperature difference between the primary and secondary coolants or by not accounting for dynamic energy transfer to and from the RCS components. The actual temperatures are not that important in this analysis as they will equilibrate after transferring energy to and from the metallic components so that the energy provided by the reactor to boil out the steam generator will be that of the decay heat.

~~Also, for conservatism in providing the minimum amount of time to steam generator dryout,~~ the initial inventory of the steam generators was considered to be that at the low-low level steam generator trip signal when the reactor trip was initiated. This was estimated to be about 90,516 (lb_m) ~~about 90% of the normal full-power liquid inventory~~. Steam generator dryout was also considered to occur when 5% of the liquid inventory was all that remained.

The total energy removal capacity of the steam generator steam and liquid inventory is estimated to be

$$E_{SG} = W_{steam} \cdot \Delta h_{steam} + 0.9 \cdot W_{liquid} \cdot (\Delta h_{water} + 0.95 \cdot \Delta h_{water\ to\ steam})$$

At the time of reactor trip with no feedwater flow, the liquid inventory is assumed to have equilibrated at the normal power saturated temperature of 1,085 psig (1,100 psia). The initial liquid inventory volume is then calculated as

$$\text{Vol} = \text{liquid inventory mass} \times V_{f\ 1,100\ \text{psia}}$$

$$= \cancel{136,135}\ 90,516\ \text{lb} \times .0220\ \text{ft}^3/\text{lb}$$

$$= \cancel{2,995}\ 1991\ \text{ft}^3$$

and the initial steam volume at 100% power is $\text{Vol}_{steam} = 7,985\ \text{ft}^3 - \cancel{2,995}\ 1991\ \text{ft}^3 = \cancel{4,990}\ 5994\ \text{ft}^3$. At the low-low level steam generator trip signal, the steam inventory will be

$$W_{steam} = \left[\cancel{4,990}\ 5994\ \text{ft}^3 + 0.10\left(\cancel{2,995}\ 1991\ \text{ft}^3\right)\right] \frac{1}{V_{g\ 1,100\ \text{psia}}}$$

$$= \frac{\cancel{5,290}\ 5489\ \text{ft}^3}{.4001\ \text{ft}^3/\text{lb}}$$

$$= \cancel{13,222}\ 13,719\ \text{pounds}$$

At 1,085 psig (1,100 psia): $h_g = 1,188$ Btu/lb, $h_f = 557$ Btu/lb

At 1,285 psig (1,300 psia): $h_g = 1,179$ Btu/lb, $h_f = 585$ Btu/lb, $h_{fg} = 593$ Btu/lb

$$E_{SG} = 4 \times \left[\cancel{13,222}\ 13,719\ \text{lb}_m \times (1,179 - 1,188)\ \text{Btu/lb} + \cancel{.90 \times 136,135}\ 90,516\ \text{lb}_m \times \left[(585 - 557)\ \text{Btu/lb} + .95 \times 593\ \text{Btu/lb}\right]\right]$$

$$= \cancel{2.89}\ \cancel{2.41}\ 2.14 \times 10^8\ \text{Btu} = \cancel{3.05}\ 2.25 \times 10^8\ \text{kW seconds}$$

or about ~~80~~ 59.3 (~~3.05~~ 2.25 × 10^8 kW seconds/3,800 MW = ~~80.3~~ 59.3 seconds) initial power seconds. If it is assumed that the reactor has been operating at full power for an extended period of time so that the fission product decay heat is nearly that associated with infinite prior operation, then, from integral decay heat curve Figure B.1-1, the steam generators are determined to "dry out" in about ~~1.4~~ 0.8 hours (~~1 hour, 24~~ 48 minutes). If the reactor had operated at less than full power, this time would be extended because of the reduced decay heat level and the larger initial water inventory. Because the effective liquid density increases as power is reduced due to fewer steam voids and lower temperature, the water inventory increases.

The above simplified analysis is intended to give an approximation of the time available for taking possible corrective actions. It neglects heat capacity effects (due to temperature changes in the RCS water inventory, the core, reactor internals, vessel, and piping) as well as delays in reactor scram or steam generator isolation, which are initiating-event dependent. Nevertheless, the rather long period of steam generator cooling provided by the large steam generator inventory should allow considerable time for operator diagnosis and corrective action.

If the RCPs continue to operate during this scenario, the dryout time will be reduced because of the additional energy provided to RCS by the RCPs. In 1 hour, assuming 95% motor efficiency, the RCPs (4 pumps, 8,000 horse power each) would provide about 7.74×10^7 Btu of energy into the RCS. The RCPs provide energy at the rate of about 0.6% of the rated thermal power. The additional energy required from reactor decay heat to dry out the steam generators will be

$$\Delta E = \frac{\left(\overset{2.14}{\cancel{2.89}} \times 10^8\,\mathrm{Btu} - 7.74 \times 10^7\,\mathrm{Btu}\right) \times 3{,}600 \text{ seconds per hour}}{3{,}415\ \mathrm{Btu/KWh} \times 3{,}800\ \mathrm{MW}}$$

$$= \overset{37.9}{\cancel{59}} \text{ full-power seconds of decay heat}$$

and, from the integral decay heat curve, this would be accomplished in about ~~0.9~~ 0.43 hours after shutdown, or ~~54~~ 26 minutes, which is ~~close to~~ less than half the 1 hour of RCP energy input assumed in the above calculation. Therefore, if the RCPs are running during this scenario, the time for the steam generators to dry out would be reduced from ~~1 hour~~, ~~24~~ 47 minutes, to about ~~54~~ 26 minutes.

As the steam generator water level drops substantially, the recirculation flow within the steam generator and the primary-to-secondary heat transfer would be expected to be reduced. This would cause primary temperatures to increase and would eventually result in pressurizer PORVs opening, loss of primary (RCS) inventory, and eventual core uncovery if ECCS is not supplied.

Note: Assuming the initiating event is a loss of offsite power (LOSP), the entire nominal steam generator inventory would be available to remove decay heat following reactor trip.

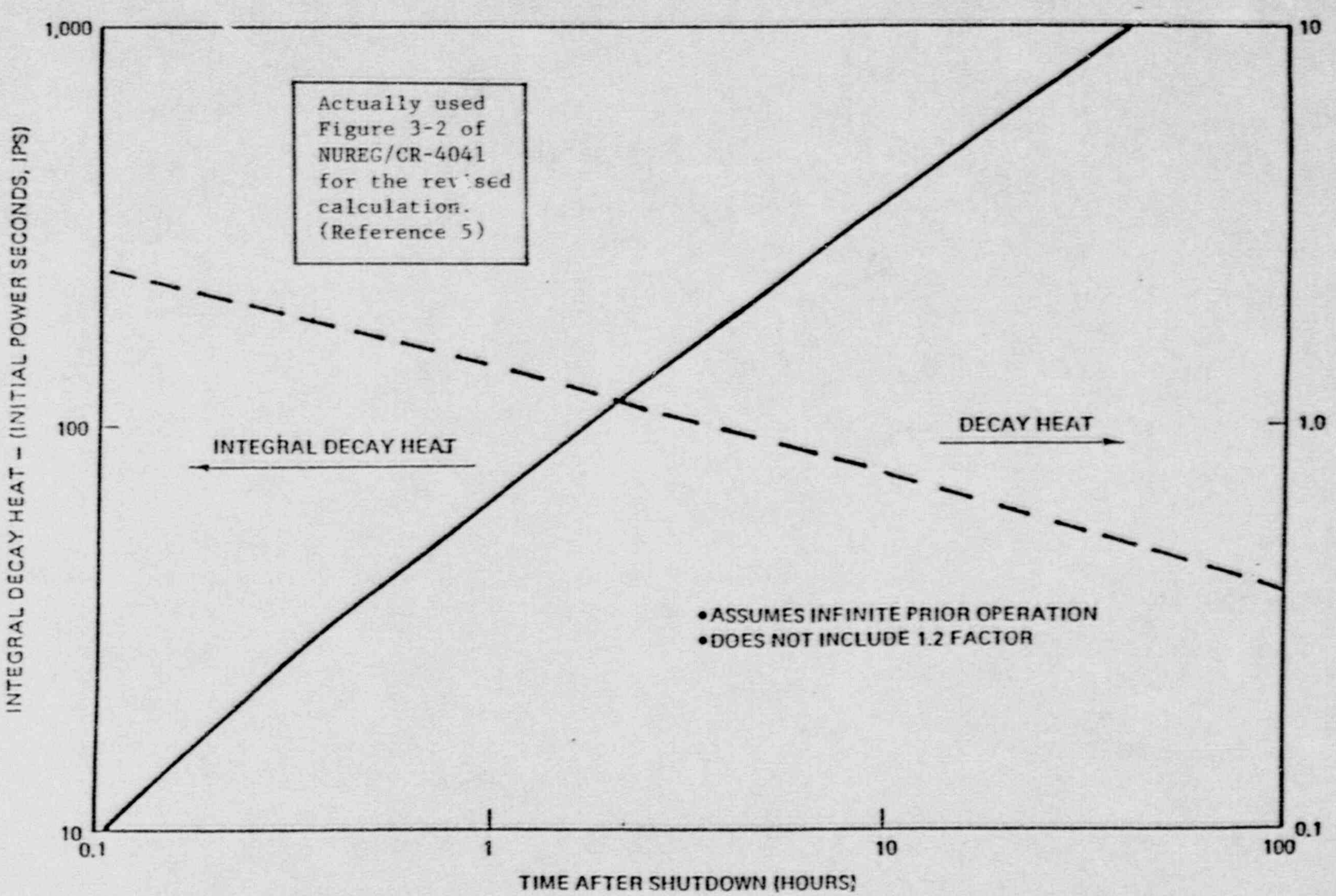

Figure B.1-1. LWR Decay Heat/Integral Decay Heat Curves

ATTACHMENT 1
ST-HL-AE-3380
PAGE 12 OF 12

ATTACHMENT 2

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.")

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 focussed 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.