Attachment D (#2, continued)

SUPPLEMENTAL ANALYSES

and

COMMENTS/RESPONSES TO EPRI/WOG ANALYSIS

of

DECAY HEAT REMOVAL RISK AT POINT BEACH

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The EPRI/WOG analysis of decay heat removal (DHR) risk at Point Beach (NSAC-113)[1] is essentially a rework, or "annotated review," of the NRC-sponsored Sandia case study (NUREG/CR-4458)[2]. Because the range of issues raised by the EPRI/WOG re-analysis is rather broad, this response report is in two parts. In Part 1, the dominant accident sequences are used as a basis for reviewing the issues, highlighting areas of agreement/disagreement, and assembling comments. In Part 2, more detailed analyses and discussion of several specific topics are included. Whenever possible, a summary of open questions or discussion topics are included. This response also incorporates comments/observations based upon supplemental information received March 31, 1988 in the meeting with EPRI/WOG and April 14, 1988 in a meeeting with EPRI and SAIC.

1. DOMINANT ACCIDENT SEQUENCES

1.1 Internal Events

The dominant internal event sequences are shown on Table 1 (Table 8.3, EPRI/WOG). The sequences are discussed in groups, rather than singly, beginning with the small break LOCAs.

1.1.1 Small Break LOCAs

For the small break LOCA sequences, $S_2MH_1'H_2'$, $S_2MD_1D_2$, and S_2MXD_1 the differences include: the small break LOCA frequency; CCW success criteria; and operator actions.

Initiating Event Frequency: A recalculation of the S_2 sequence frequencies using the EPRI/WOG initiating event frequency of 3E-3, with no other changes, leads to an estimate of core melt

TABLE 1

Comparison of Core Melt Frequency Estimates

Sequence	NRC Case Study	EPRI/WOG Study	Key Reasons
	Core Melt Frequency Per Reactor-Year		
$S_2MH_1H_2$	4.7E-5	5.8E-7	SBLOCA Freq. Operator Action
T_1MLE	6.7E-6	7.7E-7	New Batteries
$T_3QH_1H_2$	2.5E-5	N/A	Rel Valve LOCA cannot occur
$T_2MQH_1H_2$	3.5E-6	1.9E-7	Rel Valve Prob Operator Action
$S_2MD_1D_2$	8.7E-6	9.5E-8	SBLOCA Freq. CCW Suc Crit
$T_3QD_1D_2$	4.6E-6	N/A	Rel Valve LOCA cannot occur
T_2MLE	6.6E-7	1.0E-7	MFW Recovery Alt to 1 PORV
$T_2MQD_1D_2$	6.6E-7	4.1E-8	Rel Valve LOCA CCW Suc Crit
S_2MXD_1	5.7E-7	1.0E-8	SBLOCA Freq. CCW Suc Crit
T_5MLE	9.1E-7	1.3E-8	DC Bus X-conn MFW Recovery
T_4MLE	6.2E-7	N/A	Loss of AC Bus does not trip
T_2MLH_1	2.0E-8	1.0E-7	Operator Action MFW Recovery
$T_1QD_1D_2$	<1.0E-8	1.2E-7	Rel Valve LOCA more likely
LTSB	3.6E-5	5.4E-7	DG-CM Values Long Term Clg
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	1.34E-4	2.56E-6	

frequency for these three sequences of 8.4E-6/rx-yr or a <u>reduction</u> of 4.76E-5/rx-yr from the 5.61E-5/rx-yr reported in the SNL study. The total reduction reported by EPRI/WOG is 5.45E-5/rx-yr. Therefore, the revised S_2 frequency alone accounts for 86% of the difference between the NRC/SNL values and the EPRI/WOG values. SNL used a value of 2E-2/yr for the S_2 frequency because all breaks between 0.38" and 1.66" were included. This is consistent with several other PRAs, e.g., the Sequoyah analysis[3] for NUREG-1150. However, that study notes that their S_2 includes the very small LOCAs (S_3 in some nomenclatures with diameter <0.5"). Thus, the Sequoyah analysis would support an S_2 frequency on the order of 1E-3/yr for equivalent diameters >0.5" and <2". The Surry analysis[4] for NUREG-1150 used 1E-3/yr for the S_2 frequency. Based upon the rationale presented by EPRI/WOG and that in the Oconee PRA[5], the proposed value of 3E-3/yr appears reasonable. This "acceptance" is also predicated, in part, upon the argument that recirculation is not required for very small LOCAs because of the extended time required to exhaust the RWST inventory at low flow rates. A plant specific analysis of flow rates and timing would be beneficial. It is also presumed that containment suppression is not required during the early injection phase of an S_2 LOCA, (an argument also made in the Sequoyah and Surry analyses) which will further extend the length of time that the RWST inventory is available for injection. The SNL study was intended to consider steam generator tube ruptures (SGTR) as an initiating event as noted in the Analysis Plan[6]. However, it was not explicitly treated as an initiating event in the case studies. There was an implicit assumption that a single tube (or even two tube) rupture would be "covered" by the S_2 frequency. If EPRI/WOG were to consider SGTR events, then the combined frequency would be on the order of 1E-2/yr based upon the 8.6E-3/yr for SGTR suggested in the Oconee PRA, although other PRAs have suggested SGTR frequencies on the order of 2E-2/yr. It is noted however, that the sequences which could lead to core damage given an SGTR, i.e., SGTR followed by failure of HPI or AFW, and failure of a SG-SV to close after being demanded to open, are minor contributors to the estimate of core melt frequency.

In summary, for Point Beach, the EPRI/WOG proposed value for S_2 frequency appears reasonable. It would also seem reasonable to consider S_2 frequencies on this order for other PWR analyses, nevertheless, it is recommended that any such use be supported by updated small LOCA data reviews which explicitly consider the question of seal LOCAs and SGTRs. Additional analytical support for the assumption that recirculation will not be required would be helpful.

Support System Dependencies: The EPRI/WOG study also asserts that CCW is not required for the HPI pumps in the injection mode because CCW provides seal rather than bearing cooling. The study also claims that removing the requirement for CCW to support HPI reduced core damage frequency by about 3.6E-5/rx-yr for related sequences (p 3-21 NSAC-113). Since the injection failures only appear in five of the dominant sequences in the SNL study, two S_2 and three T, the sum of which is less than 1.5E-5/rx-yr, this appears to be an editorial oversight.

In the March 30, 1988 EPRI letter to Sandia[7], and during the March 31 meeting, EPRI/WOG reiterated their position that component cooling water is not required for HPI pumps in the injection mode. Specific test data from the John Crane Seal Co. was presented to support this position, therefore it is accepted. On this basis, a cursory re-examination of the sequences involving injection suggests that removing the CCW dependency reduces the core melt frequency by a further 3-10% depending upon the particular sequences examined.

Operator Actions: The final area which EPRI/WOG credits for significant reduction in core melt frequency is operator action, particularly in the case of the S_2, the failure to switchover from injection to recirculation. SNL used the generic value of 1E-3/demand* while EPRI/WOG used 1E-4/demand, based on the assertion (p 4-10 NSAC-113) that, "there would be many people watching and verifying its implementation." Given that there have been "many people" in a number of plant control rooms during critical incidents and that mistakes were still made, the EPRI/WOG rationale, as stated, seems weak. It is also noted that the Oconee and Sequoyah PRAs use values in the 1E-3/demand range, although they do show variation with the time available to make the switchover. The SNL/NRC review of the Indian Point PRA[8] describes analyses which can produce failure rates from less than 1E-4 to greater than 1E-3. It would appear that 1E-3/demand is a reasonable value to use when a detailed HRA is not available, i.e., a generic study. However, lower values may be substantiated with some modest amount of analysis, so long as it is more substantive than that offered by NSAC-113. [It may be anticipated that HRA and associated human failure rates will continue to be an area of some contention and disagreement among PRA practioners because of the lack of "hard data" and the often subjective nature of the analysis. In the author's opinion, the general tendency of industry-sponsored PRAs is to adopt more favorable (optimistic) HRA values whenever possible while NRC-sponsored PRAs, for obvious reasons, tend to adopt conservative values.]

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* Although Table B.2, p B-26, NUREG/CR-4458 shows HPRF-MANACT as 3E-3/demand, it will be noted from the actual analysis, Table B.22, p B-81, that the only term used is SUMP-VCC-OE at 1E-3/demand.

1.1.2 Loss of Offsite Power

For the loss of offsite power (LOSP) transients T_1MLE and $T_1QD_1D_2$ the key differences are: LOSP frequency, new batteries, and relief valve LOCA probability.

Initiating Event Frequency: The use of a site specific frequency for LOSP rather than the national average is a reasonable approach *if* the objective of a study is to get the best estimate for a particular site. Given that the goal in the case studies was to gain some insights on a more generic basis the industry average was a better value to use. In this instance the difference is nominal, 0.062 versus 0.084 per year, which accounts for only about 27% of the reduction in the T_1 sequences or 8% of the overall reduction in core melt frequency due to internal events.

Support System Dependencies: In some respects, the new station battery, added to back-up the the normal station batteries, makes the plant analyzed by EPRI/WOG a different plant than that analyzed by SNL. [If these batteries were installed in 1985, it is difficult to understand why SNL wasn't made aware of them during the various plant visits and interactions, particularly since this new set is intended to provide back-up DC power for diesel starting and vital plant instrumentation.] It is not easy to quantify the contribution these new batteries would make without re-analysis of the EPS with these batteries included. The information provided in Appendix B of the EPRI/WOG study indicates, for instance, that for one sequence involving battery common-mode failures and manual operation of the turbine driven auxiliary feedwater system, the core melt frequency decreases by more than an order of magnitude when the new batteries are considered. Unfortunately, NSAC-113 does not provide complete information as to the values selected for the other terms and thus we are unable to reproduce the results. Based upon comments in Section 5 (page 5-4, NSAC-113) and discussion with SAIC, it is our understanding that EPRI/WOG essentially treated the new battery as a "recovery" action, adjusting the credit to account for potential equipment failures as well as personnel actions. Given that the new battery exists, it is appropriate to include its use in any analysis. A very "approximate" hand calculation for sequence T_1MLE yields a value of 1.09E-6 per rx-yr for the core melt frequency. This is about 40% greater than the 7.7E-7/rx-yr reported in NSAC-113, so there are still some differences in the manner in which credit given.

The EPRI/WOG report also indicates that the sequence $T_1QD_1D_2$ will appear because there is an increased liklihood of a relief valve LOCA and on page 2-10 this is labeled as a blackout sequence. In the case study analysis AFW suceeds in this sequence, however in Appendix B of NASC-113 all the sequences listed for T_1 transients involve T_1M-Q and some type of AFW failure. Based upon discussions with SAIC, it appears that portions of Appendix B did not get updated before printing, but it is our understanding that SAIC did make the required adjustments to the individual cut sets to appropriately produce this sequence.

1.1.3 Loss of Feedwater Transients

For the loss of feedwater (LOFW) transients $T_2MQH_1'K_2'$, T_2MLE, $T_2MQD_1D_2$ and T_2MLH_1 the key differences are: relief valve LOCA probability, operator actions, main feedwater recovery, alternatives to 1 PORV, and CCW success criteria.

Relief Valve LOCA Probability: Although both the Case Study and NSAC-113 report sequences which involve transient induced LOCAs, ie., event Q, it should be noted that the two studies deal with different situations. The Case Study baseline analysis assumes that the PORV block valves are closed so that event Q involves openings of the SRVs. On the other hand, NSAC-113 assumes that the block valves are normally open, so that in that analysis event Q involves the PORVs. Therefore, some care must be exercised in comparing the results. The EPRI/WOG study assumes that PORVs will open for LOSP, LOFW and loss of AC or DC bus, but they argue that W thermal-hydraulic calculations (no reference) show that reactor and turbine trips will not result in PORV openings. NSAC-113 also cites a W survey[9] of PORV and SRV events indicating that there were no failures of PORVs in some 163 operational openings and no SRV operational openings, therefore no failures. It is agreed that if there are PORV openings as a result of some transient, it would not be expected that the SRVs would receive any challenge. But as noted above, this represents a different base case than that analyzed by SNL in which the PORV block valves were presumed to be closed*. Therefore, a potential for challenge to the SRVs exists, although, in these sequences in which AFW succeeds the liklihood of such a challenge is presumed to be small. Some Westinghouse analyses, apparently unpublished[10], suggest that SRV set points would not be reached. However, at the time the case studies were prepared, information was available to SNL which suggested that PORVs and SRVs might open inadvertently even when they were not demanded, the 0.07 value. Based upon NUREG/CR-2728[11] it was then assumed that the probability that once opened the safety

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* This conservative approach was taken based upon our impressions from conversations with the plant staff suggesting that block valves were "often closed" due to leaking PORVs.

valve didn't close is 0.01, so since both valves have to reclose to prevent a small LOCA, the value is 0.02, and the T_2MQ product was computed from the relationship:

T_2(Freq of LOFW) * M(Loss of PCS) * Num of SRVs
* Prob SRV opens inadver * Prob open SRV doesn't reclose

or

$$T_2MQ = 1 * 1 * 2 * 0.07 * 0.01 = 1.4E-3/yr$$

Accepting the argument that the 0.07 value is conservative for SRVs, other studies[12] still suggest that SRVs may be demanded about 1% of the time even with AFW available. On this latter basis, the T_2MQ product becomes 2E-4 and the resulting core melt frequence for $T_2MQH_1'H_2'$and $T_2QMD_1D_2$ would be a factor of seven lower or 5E-7 and 9.4E-8 per reactor-year, respectively considering only a change in the event Q liklihood for SRVs.

In contrast, the EPRI/WOG study assumes that the PORVs are generally <u>unblocked</u>, but accounts for the possibility that they may be blocked some fraction of the time. Again, this is a different situation than that analyzed by SNL. However, the approach suggested by EPRI/WOG seems reasonable, providing that adequate data on block valve status is available. Assuming that the block valves are essentially always open, NSAC-113 estimates the value of T_2MQ as:

T_2(Freq of LOFW) * M(Loss of PCS) * Num of PORVs
* Prob PORV opens * Prob PORVs don't close if open
* Failure to close block valve

or

$$T_2MQ = 1 * 1 * 2 * 1 * 5E-3 * (8E-3 + 1E-3) = 9.05E-5/yr$$

where 8E-3 is failure per demand of the block valve and 1E-3 is operator failure to close the valve in 30 minutes. NSAC-113 states that "one percent of the time a PORV will stick open or 5E-3 per valve." However, the data reference used in the Case Study, NUREG/CR-2728[11], indicates (p -127) that for <u>relief</u> valves, "failure to close, given open," is 2E-2, a factor of four higher. In addition, because of the more generic approach of the Case Study we would have used 3E-3 for the operator error term. Therefore, had we used this approach, the case study probably would have reported a value of 4.4E-4/yr for T_2MQ. It is interesting to note the results if one uses the block valve position data provided in the March 30 letter[7]. That is, both block valves closed 22% of the time and both open 48% of the time. Using the NSAC-113 values and the revised Case Study values one can obtain:

$$T_2MQ = (0.48 * 9E-5) + (0.22 * 2E-4) = 4.32E-5 + 4.4E-5$$
$$= 8.72E-45/yr$$

If one used the larger results that would arise using the NUREG/CR-2728 data on relief and safety valves, one gets:

$$T_2MQ = (0.48 * 4.4E-4) + (0.22 * 2E-4) = 2.11E-4 + 4.4E-5$$
$$= 2.55E-4/yr$$

This suggests that values for T_2MQ (whether PORV or SRV) on the order of 1E-4 to 3E-4 are not unreasonable. Therefore, it is agreed that in a plant specific study the probability of transient induced LOCA could be lower than was initially suggested by SNL.

It is not clear from the EPRI/WOG discussion how their main feedwater recovery differs from that employed by SNL, i.e., a non-recovery in 60 minutes of 0.1. In fact, they seem to be consistent given the comment made on sequences T_2MLE and

T_2MLH_1, although for T_2MLH_1 it appears that they used a larger value for non-recovery (about 0.6) and then took credit for added operator actions.

A. hough NSAC-113 implied that alternative venting paths were employed (Table 8-3, page 8-4), it was not obvious how the credit was taken. Subsequent information in the March 30 letter[7] indicates that the venting capability was not actually credited because of down-stream orifices in these lines. But, EPRI/WOG does suggest that the analyses which require both PORVs for successful feed and bleed are too conservative, and if so, the added venting would be beneficial. This is an area which requires more difinitive analysis before any significant changes are made in success criteria.

As noted earlier, EPRI/WOG has supplied test data which supports the removal of the HPI dependency upon CCW in the injection mode. A manual calculation which removes the CCW dependency yields a further reduction in the estimated core melt frequency for $T_2MQD_1D_2$ to 2.6E-8/rx-yr, somewhat lower than the 4.1E-8/rx-yr reported in NSAC-113. But again, the qualitative difference between the two analyses must be kept in mind. Also, manual re-quantification of the sequence cut sets without re-evaluating the Boolean expressions may lead to erroneous results when dependencies are being completely removed, especially if potential recovery actions are not adequately treated.

1.1.4 Other Transient Sequences

For the remaining transients, $T_3QH_1'H_2$, $T_3QD_1D_2$, T_4MLE, and T_2MLE the EPRI/WOG report argues either that they do not, or cannot, occur or that they are significantly reduces by the availability of DC cross-connects and main feedwater recovery.

<u>Miscellaneous T_3Sequences</u>: For the sequences $T_3QH_1'H_2'$ and $T_3QD_1D_2$ the argument is made (as noted above) that in some 163 openings of PORVs at <u>W</u> plants no failures of PORVs have been reported and that no operational openings of SRVs have occured. It is stated that <u>W</u> thermal-hydraulic <u>calculations</u> show that reactor and turbine trips <u>will</u> <u>not</u> result in PORV opening. It is assumed that this is a reference to unpublished calculations[10], since no reference is cited. While PRAs are built upon experience to the maximum extent possible, it does not appear reasonable to completely reject a possible sequence simply because it has not yet occured. As noted above, the SNL analysis of inadvertent openings may be more conservative than necessary and the actual contribution may be considerably less, but the EPRI/WOG study does not provide sufficient evidence at this point to conclude that these two sequences "cannot occur."

<u>Loss of DC Bus</u>: For sequence T_5MLE, recovery of main feedwater and DC bus cross-connects are cited as reasons for change. The SNL study had already accounted for main feedwater recovery (NUREG/CR-4458, Appendix B, Section 6.3, page B-115). The existence of cross-connects is recognized, in fact they are shown on Figure A.8, page A-23 of the Case Study. It seems that the discussion of the cross-connection recovery (page A-9, NSAC-113) is approximately an order of magnitude "off" from the way we would read the references cited. The Case Study would yield a p(NR) outside the control room of 0.3 in 10-20 minutes, while the NUREG/CR-1278[13] data cited (Table A-3, page A-8) would support 0.01 at 20 minutes. Thus, while the concept of DC recovery by cross-connection appears reasonable, the details of the application will have to be better understood before a firm recommendation can be made. For sequence T_4MLE, the EPRI/WOG study simply states that an evaluation by WEPCO indicates that

loss of an AC bus will not cause a plant trip. Without additional detail it is impossible to comment on the acceptability of this statement. It would appear that a more reasonable argument would be improved recovery such as was argued for the DC bus, although the probabilities need to be examined.

1.1.5 Long Term Station Blackout

Initiating Event Frequency: Although the factors causing the differences between the EPRI/WOG study and the SNL results are not as explicitly spelled out for the long term station blackout as for the other sequences, they are relatively easy to identify. They are: reduction in T_1 frequency, reduction in DG failure rate, and recovery via long term cooling. As noted earlier in the discussion of LOSP induced transients, the use of "bonafide" site data in a site specific study is acceptable; here the site specific T_1 frequency is about 78% of the national average.

Support System Dependencies: The EPRI/WOG value for DG failure rate is based upon more recent compliations of data. If independent assessment of NSAC-108[14] indicates that the data is valid, and there is no reason to believe that it isn't, then there would be no problem using the newer data. It should be noted that the SNL value, 3.8E-2, included two components; a 1.9E-2 failure to start and a 1.9E-2 failure to run eight hours. Although it is not so stated in the EPRI/WOG analysis, based upon prior conversations with the NSAC staff and information in the March 30 letter[7], the 2.2E-2 is a combined failure to start and run for two to three hours. A specific time is not cited in NSAC-108 or the letter, but given the postulated mission requirements the two to three hour time frame seems a reasonable estimate. On this basis, the NSAC-113 value is actually quite consistent with the data used by SNL, the difference being the required run time. It is understood that industry would argue for the shorter run time based upon the probability of the recovery of offsite power (see March 30 letter[7]). SNL chose the 8 hour time to be consistent with the approach then being taken for the resloution of USI A-44, Station Blackout. Applying the revised T_1 frequency and DG failure rate to the SNL estimates produces the values shown in Table 8-4 of NSAC-113 under the column labeled Total Frequency of Blackout Not Causing Early Core Damage. The exception seems to be that for the entry DG-CM, NSAC-113 only reflects the reduced T_1 frequency, an apparent oversight. If one were to use the DG-CM values cited in Table 5-2, page 5-11, this value would be 2.26E-6/rx-yr. However, it is believed that the value cited for DG-CM is quite optimistic for two train systems. The study by Hirschberg and Pulkinnen[15] would support values in the 10^{-3} range. Using the SNL approach (NUREG/CR-4458, Appendix B, page B-34) with the NSAC-113 value for DG-LF yields a DG-CM of 8.8E-4 per demand. Incorporating this latter value into the study would reduce the initial EPRI/WOG estimate of LTSB to 9.94E-6/rx-yr.

The EPRI/WOG study, as we understand it, argues that the new batteries allow the operators to continue to run the AFW system during station blackout. Although we will accept the premise, it is not clear how it will be accomplished. The analysis of NSAC-113 appears very optimistic about how easy it will be to accomplish certain tasks during actual blackout conditions. [See also comments to the Advisory Committee on Reactor Safeguards by ACRS Consultant P. Davis.[16]] A similar situation exists here using diesel driven fire pumps to refill the CST. Although there is reasonable time to accomplish the refilling, it is not clear that this has been demonstrated with the plant actually blacked out. It is stated that p(NR) for 20 minutes would seem appropriate and that the unavailability of pumps and hoses would dominate the failure probability so that an overall probability of 0.03 was "deemed reasonable." It is impossible to adequately comment without more detail on the rationale behind these statements. Therefore, it is recommended that the estimate of core melt which only accounts for the site specific LOSP frequency and the revised DG-LF probabilities and not long-term cooling be retained pending a more definitive explanation by EPRI/WOG of their long term cooling analysis. This yields a value of 9.9E-6/rx-yr for the LTSB contribution, as noted.

1.1.6 Revised Estimate of Core Melt Frequency - Internal Events

Based upon the preceeding arguments and discussions a "revised" summary of the core melt frequency estimate is shown on Table 2.

1.2 <u>External Events</u>

The special emergency (external events) with which EPRI/WOG disagreed are shown in Table 3. NSAC-113 states that the risk related to external events, flood, high wind and lightning are each below 1E-8/rx-yr because of conservatisms in the SNL analysis and because "WEP has strengthened the diesel generator exhaust supports, i.e., the vulnerability identified in the NRC Case Study." Obviously, if a vulnerability that was previously identified is reduced or eliminated, there is a reduction in core melt frequency, although SNL estimates for wind would still be on the order of 1E-7/rx-yr. Specific comments on the seismic, fire and internal flood analyses follow below.

1.2.1 Seismic (Comments prepared from material by M. Bohn/SNL)

NSAC-113 reports a total seismic contribution of 7.4E-6/rx-yr as compared to the SNL result of 6.5E-5/rx-yr. The reduction was attributed to four factors: a lower hazard curve, newly-installed (upgraded) emergency batteries, alternate water sources for the RWST, and recovery actions following the earthquake. Each of these is discussed briefly below.

TABLE 2

Comparison of Modified Core Melt Frequency Estimates*

Sequence	NRC Case Study	Revised Value	Key Change
	Core Melt Frequency Per Reactor-Year		
$S_2MH_1H_2$	4.7E-5	7.02E-6	SBLOCA Freq.
T_1MLE	6.7E-6	4.94E-6	T_1 Freq
$T_3QH_1H_2$	2.5E-5	3.57E-6	Rel Valve LOCA frequency
$T_2MQH_1H_2$	3.5E-6	5.0E-7	Rel Valve Prob
$S_2MD_1D_2$	8.7E-6	9.2E-7	SBLOCA Freq. CCW Dependency
$T_3QD_1D_2$	4.6E-6	1.8E-7	Rel Valve LOCA CCW Dependency
T_2MLE	6.6E-7	6.6E-7	None
$T_2MQD_1D_2$	6.6E-7	2.6E-8	Rel Valve LOCA CCW Dependency
S_2MXD_1	5.7E-7	3.6E-8	SBLOCA Freq. CCW Dependency
T_5MLE	9.1E-7	9.1E-7	None
T_4MLE	6.2E-7	6.2E-7	None
T_2MLH_1	2.0E-8	2.0E-8	None
$T_1CD_1D_2$	<1.0E-8	<1.0E-8	None
LTSB	3.6E-5	9.9E-6	T_1 Freq DG-LF Value
Total Internal	1.34E-4	2.93E-5	

* (Based upon "accepted" changes to data, see text)

TABLE 3

Comparison of External Event Core Melt Frequency Estimates

Accident Type	NRC Case Study	EPRI/WOG Study	Revised NRC Case Study
	Core Melt Frequency Per Reactor-Year		
Seismic	6.1E-5	7.4E-6	4.1E-5
Fire	3.2E-5	6.3E-8	2.2E-5
Internal Flood	7.7E-5	<1.0E-8	8.7E-7
Wind	4.0E-6	<1.0E-8	1.7E-7
External Flood	1.9E-8	<1.0E-8	1.9E-8
Lightning	5.8E-8	<1.0E-8	5.8E-8
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	1.7E-4	7.5E-6	6.4E-5

NOTE: These "revised" estimates in some instances use an approach or values which are still open for discussion, but they are provided to illustrate the sort of reduction that may be reasonable.

The Hazard Curve: SNL does not agree with this modification, as it has no specific analytical basis. The EPRI/WOG analysis reduced the Case Study hazard curve by a factor of 2 at the SSE and a factor of 5 at the 3 SSE acceleration, but no site-specific reanalysis was performed, The only rationale provided was that the EPRI Hazards Program tended to get hazard curves lower than the Lawrence Livermore Hazard Program curves by the factors given. However, SNL used the LLNL results for shape only, and scaled the Point Beach SSE to a frequency of 2.5E-4/yr, typical of most Eastern U. S. sites. Then the curve was modified for local soil column effects. We would not agree to the EPRI/WOG curve unless a site-specific analysis were performed. We believe the hazard as presented in the Case Study is realistic. However, it is also our understanding that site-specific hazard curves are in preparation as part of an ongoing EPRI-NRC technical interchange. This question can be re-addressed when that dialogue is concluded.

New Batteries: New batteries have been installed which meet seismic Category I standards. As failure of battery racks was a significant contributor to the seismic results, we are pleased that such a modification has taken place. However, taking full credit for these new batteries would only reduce the seismic core damage frequency to 4.1E-5/rx-yr in the SNL analysis, less reduction than implied by the EPRI/WOG report. A number of topics warrant further discussion. Are the new batteries full-station emergency batteries or are they dedicated to the diesel generators and perhaps a few specific pieces of instrumentation? As we understand it this latter situation applies. Even though the new installation is seismically qualified to the SSE, is there sufficient margin in the design above the SSE where the seismic risk is greatest? [See also, comments to the Advisory Committee on Reactor Safeguards by ACRS Consultant P. Davis.[16]]

Alternate Water Sources for the RWST: The EPRI/WOG reanalysis takes credit for manually aligning other (presumably undamaged) water sources to replace the RWST, based on: a) a letter from EQE to WEPCO[17] stating that most free-standing vertical water storage tanks have behaved well in earthquakes, and b) the assumption that any failure of the RWST would not be instantaneous, but would allow time for such manual realignment. It should be noted that no reanalysis of the RWST fragility was performed. We do not agree with these assumptions for the following reasons:

a) The Point Beach RWST is an anomalous design which is outside the SQUG data base. Its dimensions (76' high by 25' outside diameter) are very nontypical. In our judgement, based on fragility calculations, significant buckling and extensive cracking are possible, with quite rapid failure.

b) We would not give credit for manually aligning other sources of water in a short time frame due to aftershocks, confusion, loss of normal lighting, additional failures, etc.

c) Any alternate water sources would have to be analyzed and their seismic adequacy verified. It does not appear that this was done by the EPRI/WOG group.

Recovery: In the SNL seismic PRAs, credit is not taken for short term recovery actions (less than about 1/2 hour) due to the effects of aftershocks, confusion, etc. We believe this is a realistic approach.

Summary: Including the new batteries, the SNL predicted seismic risk would be 4.1E-5/rx-yr, a value substantially greater than the 7.4E-6/rx-yr reported in NSAC-113. At this time we do not concur with the other changes suggested.

1.2.2 Fire (Prepared in part from material by W. Wheelis/SNL)

The comments in NSAC-113, as well as comments from various other industry reviewers, indicate that there may be some significant misunderstandings about the Case Study fire analysis, in addition to some disagreements with the approach. For example, EPRI/WOG states on page 6-4, NSAC-113, "The NRC Case Study scenarios focused on transient combustible fires. "In response to similar comments SNL has stated that this is not the case. Appendix D of the Case Study (page D-7) states,

"c. Two transient combustible exposure fires were assumed to bound all transient and electrically-initiated fires." (Emphasis added).

Later on in that same section it states,

"Electrically-initiated fires are not being explicitly evaluated, but it is assumed that the exposure fires postulated for this analysis bound any transient or electrically-initiated fire that might occur at a plant."

Because it is impossible to analyze every conceivable situation, the assumption in the fire analysis was that the two fire sources used, trash can and acetone spill, were representative, in a bounding sense, of the energetic of cable fires (in situ source) or transient combustible fires that might be present in a particular location.

There is no way for an analyst to state exactly how much of, or where, a transient fire source will be in a room, or where, a priori, an electrical cable might self-initiate due to a short circuit or overload. Certainly, based upon historical data, fires at nuclear plants have involved both transient combustibles and self-initiated cable fires. Thus, it was intended that the selection of fire sizes (ie., fire energetics) bound these sources. The trash container size was based upon the likely size of container to be found at the plants, while the 10 gallon spill was based upon information in a number of utility Appendix R submittals which indicated that a source this intense was required to create problems. Thus, the use of this size a source for energetics calculations is conservative. In addition, worst case geometries were used in assessing fire growth and spread in order to maintain the conservatism.

Discussions with EPRI/NSAC personnel have revealed that the two major areas of concern and/or disagreement lie with the amount of acetone which might be present (and the way the spill is modeled) and the use of the COMPBRN code. NSAC-113 stresses that at Point Beach considerable effort is directed toward controlling the amount of combustibles which may be present and that such materials are removed as soon as their use is no longer required. We would agree that in a plant specific analysis, if one is considering only the transient source, the existing administrative controls should be carefully considered in evaluating the potential consequences. Also, the room geometries should be examined to establish the degree of "pooling" which might occur. But again, this analysis, essentially done in 1984, was attempting to generate a conservative bound on all fire sources and their effects.

EPRI/NSAC personnel have also expressed their concern about the use of the COMPBRN code because of "known modeling deficiencies," although this is not expressed in NSAC-113. The decision to use COMPBRN was made in early 1984, therefore the version of the code documented in 1983 was used. It was understood then, and now, that there were some shortcomings, but it was used in other PRAs and it provided a vehicle for quantifying fire consequences. For example, it was only exercised in the natural ventilation mode to evaluate fire effects because the forced ventilation mode had not been adequately benchmarked at that time.

It should be noted that this portion of the quantification was intended to provide input to the intermediate decision, can a fire in this particular place, assuming worst case geometry, damage components or cables required for safe shutdown? Given the advances in the state-of-the-art in fire PRA in the past several years were the analysis to be re-done today, in all probability, this portion of the quantification would be done differently.

A significant area of difference between the two studies is in the estimates of fire frequency. SNL used generic data for auxiliary building fire frequency and, using actual fuel loading information provided in the Point Beach Appendix R submittal, developed a frequency for the particular room of concern. In contrast, EPRI/WOG used specific event data to develop their frequencies, drawing heavily upon some portions of the Limerick PRA[18]. We believe that the Limerick PRA should be used with caution since in several instances it reports a reduced liklihood of fires based on the argument (engineering judgment) that their cables are "better" than those in use when the industry-wide data was collected. Even so, when one compares the total frequency for the AFW pump room, the SNL value is only 3.7 times the NSAC-113 value, and for the switchgear room only about 1.2 times greater. Given the state-of-the-art of fire PRA at the time of the original study, these differences, although visible, are not overriding.

It is noted that the Fire Analysis Summary, Table 8-6 (page 8-7, NSAC-113) reports values for AFW-PF and SW-PF different from those reported in Section 6 (page 6-6). As a result the core melt sequence total for AFW-PF is "off" by a factor of two. The core melt sequence total for SW-PF is consistent with the frequency data from Section 6. The net result is that the NSAC-113 core melt frequency estimate for the AFW Pump Room is actually 2.84E-8/yr, and for the Switchgear Room 4.19E-8/yr; a total of 7.03E-8/yr, or about 12% greater than that reported in Table 8-6.

An additional area of difference between the two studies involves the number of suppression systems available and their effectiveness. Based upon the information available to us at the time the study was conducted, SNL gave credit for one Halon system in the AFW pump room. If there are indeed two systems, they should be credited. In that case, our estimate of core melt frequency for the AFW pump room would become 2.5E-6/rx-yr and the total fire contribution would be 2.23E-5/rx-yr or about 1/3 less than that reported in the Case Study*. EPRI/WOG has proposed that the Halon system effectiveness is much better than the industry data used by SNL on the basis of a personal communication with a DOE staff member. In the March 30 letter[7], EPRI cites as a reference for this material the "Summary of Fire Protection Programs of USDOE Calendar Year 1986" pages 29-32, no report number. They further state that the reference indicated,

> "that for 17 fires in which automatic Halon suppression systems were involved, all fires were extinguished. The EPRI/WOG study conservatively assumed one failure thereby yielding a failure probability of 1/17."

They further comment that the 1987 data is not yet available.

During the March 31 meeting with EPRI/WOG there was considerable discussion about the comparability of the recent DOE data and the American Nuclear Insurers data reported in the Millstone 3 PRA. In the March 30 letter[7] EPRI states,

> "Through discussions with Mr. Maybee, we were also able to explain the apparent difference between these Halon reliability estimates and those quoted in the Millsone 3 PRA. The American Nuclear Insurers, the source for Halon reliability estimates in

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*The comment on Table D-11, Basis for EPRI/WOG Cost Estimates, of NSAC-113, "The principal basis results from information gained from recent installation of a Halon system in the referenced room." can be interpreted to mean that the second Halon system was installed after the NRC/SNL visits.

the Millstone 3 PRA, generally quote Halon reliability estimates using the acceptance test data rather than actual experience in extinguishing fires.

Acceptance test data is not an adequate basis for predicting Halon system reliability in the event of a fire at a nuclear facility for two reasons. First, an acceptance test is part of the design checkout phase of system design and implementation. If the Halon system faills to meet its acceptance test, the system is modified and retested until the required concentrations are delivered and maintained for the required time interval. Usually an acceptance test failure is a small variation from the criteria and only minor modifications are required.

Second, the acceptance test criteria are conservative. Mr. Maybee noted that whereas most fires are extinguished (according to research data) by a 3% concentration, the acceptance tests generally require a 5% concentration to be held for 10 minutes. Further, the experience quoted in the above reference indicates that Halon systsems are more capable than their design bases suggest. In one case a Halon systsem put out a so-called "deep seated" fire, e.g., a fire starting at the bottom of a trash container. According to Mr. Maybee the research data suggests that Halon would not have put out such a fire."

Thus, EPRI/WOG seems to present a strong argument for the use of DOE data. But, while we certainly agree that additional data is desirable, it is not clear that suppression system failure probabilites and performance for DOE facilities and nuclear power reactors are directly comparable. That is, the processing plants are likely to have more stringent fire protection systems requirements (eg., more periodic testing and maintenance) than nuclear power plants. Similarly, the processing rooms are probably much smaller than the fire zones at the power plants, so that one might have suppression system success for small rooms or compartments, but not necessarily large rooms.

In fact, if one examines the data contained in the DOE report, it appears that a significant fraction of the reported events occurred in situations quite different from the conditions expected in nuclear power plants. A number of these events are in very confined spaces (2 in computers at research laboratories, 2 in glove boxes) where maintaining an adequate concentration of Halon should not be difficult. Two events involve trash can or wastebasket fires and several others involve motor or transformer fires. Furthermore, although the report states that there are 17 fires with Halon discharge, there is no indication of how many fires, if any, occurred where Halon should have been discharged but was not. Even further, based upon the introductory information in the report, it appears that the real motivation for this reporting is not to gather data on fire suppression performance or reliability, but to document how much Halon (chlorinated fluorocarbon) has been released either deliberately or accidentally. This is prompted by the world-wide concern about the effect of chlorinated fluorocarbons on the environment and anticipated Environmental Protection Agency rules on their use and release. So while one would agree that new data, if comparable, should be factored into the existing data base and not used in isolation (simply because it provides a "better" result), it is not at all clear that the DOE data is reallly applicable. The data from the Millstone PRA is based upon inspector testing data at nuclear power plants by the "American Nuclear Insurers Group" (>60 data points). It is our understanding that this is only acceptance test data. If such a re-analysis leads to an improved estimate of reliability then it should be used. However, until such issues are resolved and a combined analyis (if warranted) is accomplished, it is recommended that the SNL values for Halon system reliability be retained. This is also prompted by our understanding, based upon discussions with fire protection professionals, that Halon systems are very difficult to employ and maintain. Also, it is our understanding that maintaining adequate concentrations of Halon in a room or compartment requires that it essentially be "sealed." This increases the concern about Halon effectiveness in large rooms such as the AFW pump room and the switchgear room at Point Beach.

As a further point of information, during some recent conversations with A. Buslik of the NRC staff, he indicated that there was some information available suggesting that the potential for common-mode failures of Halon suppression systems exists. This subject was discussed during the March 31 meeting. There it was pointed out that if the reliability is of the order 0.06, then the product of two failures would not be much different than a single failure times a beta factor, given that beta factors are usually on the order of 0.05 to 0.1. If the reliablility is about 0.2 as in the Case Study, then the product of two failures would be about 5 times greater than theproduct of a single failure and a beta factor. Pending more definitive information on the applicability of the DOE data and the presence or absence of common mode effects in these systems, the beta factor issue will be neglected.

The final area of difference is in the treatment of human reliability in aligning the turbine driven AFW pump. SNL used a value of 0.1 while EPRI/WOG suggests 0.03. As has been noted elsewhere, SNL used generic values, so in some respects reduction by a factor of 3 does not appear to be a big driver. SNL did, in fact, talk with Point Beach personnel to verify that they could manually align the pump. They felt that they could and this is pointed out on page D-32 of Appendix D of the Case Study. However, it is not clear that one could use 0.03 for every room, especiallly for a fire in the AFW pump room. The Case Study presumed that the fire was in the room where you were trying to manually align a pump. EPRI/WOG has provided infor- mation showing that the valves could be controlled manually from a point outside the AFW pump room. Thus it appears tnat the key to using a lower value would be the locations involved and the time available before core melt occurs. If there is some time, say 2 to 3 hours, the 0.03 value may be appropriate, if the time is short, say 15 to 20 minutes, then the human failure probability should increase because of the stress factor. The location of controls could also affect the operator performance. So, unless very specific and detailed HRA results are available, SNL recommends retaining the more conservative generic values used in the Case Study.

1.2.3 Internal Flood

EPRI/WOG takes issues with the Case Study internal flood analysis primarily with respect to the initiating event frequency. SNL used generic data for auxiliary building pipe ruptures and applied it to the piping in the service water pump house. This approach seemed consistent with generic goals of the study. In contrast, EPRI/WOG cites a pipe break correlation by Thomas[19] which is used to develop the initiating event frequency. They cite:

$$P_C = (P_C/P_L)*(Q_P+A*S*Q_W)*BF*P$$

where: P_C = probability of break
P_L/P_C = % of breaks out of leaks (0.06)
Q_P = risk quantifier = $D*L/t^2$ $(10*36/0.5^2)$ = 1440
A,S = factors related to weld quality (50,1)
Q_W = same as Q_P, but for welds (?)
BF = dynamic loading factor (2)
P = global failure rate per Q (1E-8/yr/Q)

However, when one examines the cited reference, it is found that Thomas defines the terms somewhat differently. For example, A and S are designated as developed area and fatigue stress, not "factors related to weld quality," although the empirical development yields a value of 50 for the product A*S. The term BF does not appear in the Thomas paper, the product B*F does, however. B is defined as a design learning factor, and F as a plant age factor.

A further concern is the EPRI/WOG assertion that "The service water pump house flood scenario requires a break to occur in one specific T-joint in the fire main." This is then used to specify only a three-foot segment in the calculation of Q.

It would appear that a more reasonable challenge to the Case Study approach would be to question the "assignment" of the auxiliary building moderate break frequency to the service water pump house. If the frequency had been adjusted somehow to account for the amount of piping present (an approach analogous to that used for the fire analysis in which fuel loading was the parameter) we might be on firmer ground. A very cursory examination of just the amount of service water piping suggests reduction of at least an order of magnitude, and possibly more, from the 2E-2 originally used taking this sort of scaling approach.

A more extensive discussion of this particular event and its treatment is provided in Section 2.1.

1.2.4 Revised Estimate of Core Melt Frequency - External Events

Based upon the preceeding discussion a revised summary of core melt frequency estimates is also shown on Table 3 (Page 17, third column). This assumes the EPRI/WOG approach to pipe rupture is acceptable, but modifies it to account for greater pipe length.

1.3 Other Significant Issues

There are a number of instances in which the SNL Case Study and the EPRI/WOG disagree on specific values for component reliability or event frequencies. This is perhaps most prevalent in the treatment of operator actions and recovery. In general, it is observed that whenever there are uncertainties or ranges of values for a particular event, the EPRI/WOG generally takes the more optimistic view. Unfortunately, this relies heavily upon engineering judgment or opinion.

For example, although feed and bleed is a controversial solution to decay heat removal because it does lead to containment contamination, the EPRI/WOG analysis asserts it will take place without hesitation. This assertion is based upon a classroom interview with two operators who assured the interviewer that they would conduct a feed and bleed operation. However, the report also states that Catawba operators in simulator exercises and interviews expressed reservations. The report authors chose the more optimistic view. Actual plant incidents, such as that at Davis-Besse[18], have also illustrated the operators reluctance to "open the primary." Therefore, we believe the more conservative approach in the Case Study is to be preferred.

Another example is available in the estimate of the operator error related to depressurization. The Case Study uses a human error of 1.5E-2/demand which is the basic 3E-3 error rate multiplied by a factor of 5 to account for stress. NSAC-113 uses the 3E-3 without qualification. Again, we believe this to be overly optimistic.

2. SPECIFIC TOPICS FOR REVIEW

2.1 Extended Internal Flood Analyses

EPRI/WOG in NSAC-113 takes issue with the SNL Point Beach Case Study internal flood (spray) analysis primarily with respect to the initiating event frequency. SNL used generic data for auxiliary building pipe ruptures[21] and applied that to the service water pump house. Such an approach appears consistent with the generic nature of the case studies. In contrast, EPRI/WOG cites a 1981 pipe break correlation by Thomas[19] which is used to develop the initiating event frequency. Additional details and comments follow below.

2.1.1 NSAC-113 Approach

NSAC-113 cites the relation:

$$P_C = (P_C/P_L)*(Q_P+A*S*Q_W)*BF*P$$

where: P_C = probability of break
P_L/P_C = % of breaks out of leaks (0.06)
Q_P = risk quantifier = $D*L/t^2$ $(10*36/0.5^2) = 1440$
A,S = factors related to weld quality (50,1)
Q_W = same as Q_P, but for welds (?)
BF = dynamic loading factor (2)
P = global failure rate per Q (1E-8/yr/Q)

It is possible to reproduce the values for P_C reported in NSAC-113 by assuming that the value of Q_W is 70, i.e., the three foot section has two welds, one at each end. This would be consistent with the EPRI/WOG assertion that there is only one 3-foot "T" which could cause adverse effects. This was confirmed by information in the March 30 letter [7].

However, when one examines the cited reference, it is noted that Thomas defines the terms somewhat differently. For example, A and S are designated as developed area and fatigue stress, not "factors related to weld qualilty," although the empirical development yields a value of 50 for the product A*S, and clearly the factors are related to the treatment of welds. The single term BF does not appear in the Thomas paper either. The product B*F appears where B is defined as a design learning factor, and F as a plant age factor. Thomas also notes (page 86, reference 19) that "...there are severe limitations to the potential accuracy of any prediction. The state of the art is numerically still in the order of magnitude phase. Any attempt at probability modeling must recognize this."

In the March 30 letter, EPRI provided a more complete description of their treatment of the Thomas correlation in response to questions from SNL. We find that treatment to be consistent with our understanding of Thomas' original development. According to information provided, EPRI based their use of the Thomas correlation on its use in the Oconee PRA[5] and that such use was accepted in the Brookhaven evaluation[22] of the that PRA. We do note that Brookhaven, in accepting the Thomas correlation, commented that it gave larger values for the probability of pipe rupture than would have been obtained using other data. This suggests that Brookhaven may have been taking a conservative view in their approach. More recent compilations of data[23] would suggest larger values than the Thomas correlation (See discussion in Section 2.1.2).

A further difference of opinion is the EPRI/WOG assertion that "The service water pump house flood scenario requires a break to occur in one specific T-joint in the fire main." This is then used to specify only a three-foot segment in the calculation of Q. We do not understand the rationale for only one "T". The Case Study notes that, "All pumps are in line-of-sight to the mid-section of the header." Based upon our evaluation of the geometry, it appears that the pumps can "see" on average 15-20 feet of the header. If one uses the Thomas correlation and recomputes P_C assuming a 15 foot section of pipe and 3 welds (ie., two pipe sections joined together) in a fashion similar to that of NSAC-113, the result is P_C = 2.5E-4 per year. This is not inconsistent with the range for moderate pipe breaks of 2E-4 to 3.4E-2 reported by Kazarians and Fleming[21], although it is on the lower end of the range. Using this frequency, the estimate of core melt frequency would become 8.7E-7/rx-yr which is also significantly less than the Case Study value. Nevertheless, we recommend that EPRI/WOG provide additional input on their reasons for limiting the vulnerable section to one specific T-joint.

2.1.2 Case Study Approach

If one questions the direct applicability of the auxiliary building data to the service water pump house, it would appear that an alternative approach would be to adjust the break frequency to account for the actual amount of piping present (an approach analogous to that used in the fire analysis where fuel loading is the scaling parameter). A very cursory examination of just the amount of piping in the service water header and fire mains (assuming they have comparable runs) suggests a ratio for pump house to auxiliary building on the order of 0.05. If this approach is applied, a frequency on the order of 1E-3 is obtained which then yields an estimate of core melt frequency of 3.5E-6/rx-yr. Obviously, it would be possible to refine this number with a more precise analysis of the amount of large diameter piping in the two buildings.

Wright, et.al.[23], have recently published the results of their study to establish pipe break frequency estimates for nuclear power plants. In this study, they treat piping which could cause LOCAs and other piping separately. They also provide a categorization of non-LOCA inducing pipe breaks by plant type, pipe size, leak rate, plant system and operational mode. In each instance they provide a point estimate with upper and lower bounds, UB and LB, respectively. Considering only non-LOCA inducing breaks and taking all LWRs together their results may be summarized as shown in the following table.

Category	N Failures	T Opr Yrs	LB	Point Estimate	UB
All LWR	19	789.09	1.56E-2	2.38E-2	3.50E-2
Pipe Size (>6"D)	8	789.09	4.99E-3	1.00E-2	1.81E-2
Leak Rate (>15gpm)	13	789.09	9.65E-3	1.63E-2	2.59E-2
System*	1	789.09	6.45E-5	1.25E-3	5.95E-3
Opnl Mode (Norm)	13	500.60	1.54E-2	2.59E-2	4.13E-2

* Plant systems other than RHR, CVCS, and MFW (PWR) and HPCI, Condensate and MFW (BWR)

Based upon this analysis, a pipe break frequency in the range of 1.0E-2 per year is not unreasonable, although a frequency on the order of 1.0E-3 in a system such as the fire protection system is also substantiated. If one assumes no breaks of significance in the Other Plant Systems in the 789 reactor-years reported above, then the point estimate becomes 2.8E-4/yr with LB and UB of 0. and 3.75E-3 respectively. It is worth noting that this is comparable to the value for P_C from the NSAC-113 correlation assuming 15 feet of piping. It could be asrgued that since these are plant-wide values they should be adjusted to account for the specific amount of pipe in the systems of interest. Such an approach would yield values for P_C less than 1E-4.

2.1.3 Summary

Therefore, based upon these considerations, a non-LOCA pipe break frequency less than the 2.2E-2/yr used in the Case Study is justifiable in a more precise, plant-specific study. The actual value will depend upon the specific approach. It would be expected that a reasonable value will lie between the 3.75E-5/yr reported in NSAC-113 and the 2.8E-4/yr derived in the preceeding paragraph from the data in the table. If the frequency is on the order of 1E-4/yr, then internal flood is a negligible contributor to core melt probability.

2.2 Cost (Impact) Analysis

EPRI/WOG in NSAC-113 takes the general position that for most modifications proposed, the Case Study underestimates the costs. NSAC-113 reports cost from 50% to 400% of those reported in NUREG/CR-4458. Comments on our comparison of costing follow below.

2.2.1 General Comments

It is difficult to ascertain exactly what was done by EPRI/WOG, in terms of modifying the Case Study results, for a variety of reasons. Although the individual modification design reports (Attachment A through O, to Appendix J, NUREG/CR-4458) spell out in reasonable detail the materials to be used and the work to be done, the individual cost elements are not enumerated, only summary values for labor and materials are provided. Therefore, it is difficult to see how the approach defined on page 10-10, NSAC-113 was implemented. It says in part,

"The EPRI/WOG analysis used the results of the NRC Case Study as a starting point for estimating these costs. An experienced cost estimator from WEP reviewed the estimates in the NRC Case Study (Appendix J) and adjusted those estimates where appropriate. The basis for adjustments in cost is presented in Appendix D."

This raises the question, did EPRI/WOG use the descriptions in the design reports to generate a new estimate, or was some "rule of thumb" factor applied? In several instances in Table D-11, NSAC-113, reference is made to specific projects done at Point Beach and how much they cost, but there often is no clear indication as to how applicable the cited experience is to the modification under discussion. This remains the case even considering the WEPCO comments during the March 31 meeting.

For example, on page 10-10 it is also stated:

"The basis for each increase is presented for each modification in Appendix D. Tangible evidence exists in support of each of these increases. The NRC Case Study estimated that a dedicated diesel generator battery system would cost $750,000. The actual cost of a new battery system installed at Point Beach and designed for backup capability to start the diesel generators, as well as providing power for half of the plant's critical safety instrumentation, was $3,690,000, The actual cost of installation of a dedicated battery modification based on one similar modification available, supports the higher estimate of $1,800,000 provided by WEP and used in the EPRI/WOG study."

Even so, there is no indication of how the $1,800,000 figure was generated or how a battery system for plant-wide appliation compares to a special purpose (diesel start) battery system. Based upon the descriptions in NUREG/CR-4458 (Attachment B to Apendix J) it appears that the modification proposed is much less complex than the system actually installed by Point Beach.

NSAC-113 also states:

"The general reasons for cost differences vary depending on the modification. For expensive modifications, most of the differences in cost included: (1) failure to consider some design requirements, e.g., seismic for specific aspects of the modification; (2) failure to account for existing structures and/or buried cabling at the site; (3) failure to consider costs of iteration between initial design and final installation, especially when construction of supports or structures and excavation were involved. For the inexpensive modifications, one important difference involved the fixed cost of paperwork of $10,000 for any modification."

Unfortunately, when one compares these general observations with the information available in Appendix D, NSAC-113, it is impossible to establish a solid basis for them.

Consider first item (1) above, failure to consider some design requirements. Design requirements specifically are mentioned in only two of the modifications discussed in Table D-11.

Internal 8 - Spare RHR Pump (MOD 816): NSAC-113 notes that the principal difference results from provision of a different power arrangement in response to Enforcement Bulletin Notice (IEN)

86-79. While it is reasonable to state that costs will be higher, it is not reasonable to fault the Case Study for not including a requirement which was not imposed until after the technical effort was completed.

Internal 9 - Diesel-Driven Auxiliary Feedwater Pump (MOD 817): NSAC-113 states that, "The principal difference is that piping could not go through the non-seismic turbine building. The WEP esitmate assumes construction of a new seismic buildilng to house the pump." The implication appears to be that the Case Study did propose to run piping through the turbine building and that the new constuction is non-seismic. Careful reading of Attachment M to Appendix J, NUREG/CR-4458, reveals for example,

"1.2 Design Requirements and Criteria

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.

1.2.3 Environmental
Seismic - Installation must be seismic

1.2.4 Installation
The new equipment shall be housed in a new Category I building, consisting of a single room housing a diesel generator, day tank, oil pump, battery and electrical equipment, located adjacent to, but not connected to the existing plant turbine hall. (Emphasis added)

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.
.

5.1.3 Mechanical
- Install auxiliary feedwater piping from the pump to the diesel jacket water heat exchanger then to existing AFW header. (NOTE: These headers are in the auxiliary building, not the turbine hall.)"

Also, Figure 2 Diesel Auxiliary P&ID clearly shows new room and piping to auxiliary building not to the turbine building. Therefore, although there may be differences in costs assigned to various items, it does not appear that these differences should be attributed to the causes cited above.

Consider next item (2) failure to account for existing structures and/or buried cabling at the site. This situation is mentioned in three of the comments.

Internal 11 - New Condensate Storage Tank (MOD 818): The NSAC-113 comments do not imply a failure to meet design requirements, per se, but they do imply that the Case Study did not adequately consider all the design effort required, i.e.,

"The principal difference includes the consideration that installation can not be in the area suggested because maintenance shop and offices currently occupy part of that space, and because of underground piping and cabling in the area. Additional costs include extended piping runs and rework problems for the underground cabling areas. The initial design will not succeed; construction will uncover underground cables and pipes, work will necesssarily cease, and the design would have to be redone. These rework costs can be substatial."

Several aspects of these comments are distrubing. First, during the modification design process the Case Study team visited the site and outlined what was being proposed. No one objected on the grounds that other structures were in place. Had we known that, the costs and the design would have been adjusted appropriately. The second part of the comment is distrubing because it portrays a situation in which the plant operator does not know what piping and cabling is buried or where it is buried. That would seem to make any work at the site a "hit and miss" process. Surely, that is not the case!

Seismic 1 - Seismic RWST Alternative Connection to Spent Fuel Pool:

"The principal differences include. . . increased pipe routing for seismic design, additional penetrations and more cable routing. . . (Note that the RHR pumps can already take suction from the spent fuel pool via a two-inch pipe connection."

Again it is noted that there is an implication that the Case Study modification is not seismic, but Attachment D to Appendix J of NUREG/CR-4458 clearly spells out that this will be a seismic Category I installation (1.2.3 Environmental, page J-9 and Table 1, page J-98). The question also arises here, if there is a 2" line which permits the RHR pumps to take suction from the spentfuel pool, why doesn't it appear on the P&IDs amd why wasn't it mentioned during the site visit when modifications were discussed with the plant staff?

2.2.2 Specific Comments

Spray - Intake Structure Shield Wall Extension (MOD 109:

"Principal basis is the cost to disassemble the existing wall and erect a new wall. This work is not included in the NRC Case Study which neglected to consider that the fire protection spray header over the pumps is seismically supported. Iteration is required generally for seismic construction, thereby increasing the cost."

Attachment G to Appendix J of NUREG/CR-4458 again unequivocally states in Section 5.2 (page J-130) "Remove existing shield wall." Thus, part of the above quote is simply incorrect. Furthermore, Section 1.2.1 (page J-129) states that "The shield wall shall be seismic Category I with a three hour fire rating." Based upon the design proposed in Attachment G, the issue as to how the fire protection header is supported does not appear to be of special concern.

During the March 31 meeting WEPCO provided additional information on this modification which may be summarized as follows:

WEPCO COST ESTIMATE
Intake Structure Shield Wall Extension

A-E Cost:			
	Design	500 m-hr @ $110/hr	$ 55,000
	Installation	630 m-hr @ $110/hr	69,000
Materials:			
	Structural Steel/Other Materials		32,000
WEPCO Cost:			
		400 m-hr @ $50/hr	20,000
Contractors Cost:			
	Installation	4000 m-hr @ $22.50	90,000
	Removal	1000 m-hr @ $22.50	22,500
			$288,500

NOTES:

A-E costs include all design and detailed construction procedures preparation. WEPCO costs include initial purchase orders and engineering reviews. Contractor costs include allowances for site access training, delays due to interference, setup and teardown.

In a similar manner the Case Study estimates may be summarized:

COST ESTIMATE
MOD 109 Shield Wall to Service Pumps

Material:		
Structural steel/Other material		$ 21,950
Contractor Cost:		
Installation	2468 m-hr @ $28.67/hr	70,760
Removal	58 m-hr @ 16.24/hr	940
		$ 71,700

NOTES:

Contractor costs include allowances for congestion and accessability, fire watches and clean-up, temporary construction, scaffolding, etc. These costs do not include engineering costs and construction management costs which are included in the indirect charges in the case studies. They are estimated at 10-15% of the direct for the modifications.

During the meeting the point was made that at Point Beach requires detailed procedures for any work to be done on the site. In fact, there was considerable emphasis placed upon this requirement for detailed procedures in advance of any work. We do have a question about the A-E billing rates quoted. These look more like rates consulting engineers would charge for senior people than what one would see as an "average" for a spectrum of design personnel. Also, considerable emphasis was placed upon WEPCO's requirement for extensive review and oversight of onsite work and this was cited as the reason for the WEPCO costs. This seems like a large amount of review for this type of job. We were assured at the meeting that in their view it is not. The contractor cost is where there really is a significant increase over the Case Study estimates, 4000 hours for installation as opposed to 2468 and 1000 hours for removal in contrast to 58. We did not ask at the time, but it has since seemed relevant, if there is room to erect the new wall before removing the old, why bother to remove it at all?

It will not be possible to "resolve" the differences in the costs without very detailed comparison of the two processes. It is not clear at this point that there is enough information to do that, or that it would be productive in terms of resolving the DHR issue.

Internal 9 - Diesel-Driven Auxiliary Feedwater Pump (MOD 817): WEPCO estimates costs at $8,000,000 (or $9,000,000 from the March 31 meeting) versus the $2,606,000 in the NRC Case Study. As noted above, the comment in Table D-11 implies that the differences arise because piping runs will be longer than those used by the Case Study and because WEPCO uses costs for a Seismic I building and the Case Study did not. As will be shown below, the Case Study did cost for a Seismic I deisgn. The Case Study cost estimates were generated using the general method outlined in NUREG/CR-3791[24], the Handbook for Cost Estimating, information from the Energy Economic Data Base[25] and the Technical Assessment Guide[26]. This information was augumented with local cost experience during the site visits. Based upon the comments in NSAC-113 and those during the March 31 meeting, WEPCO has relied heavily upon "comparison" with similar projects rather than direct line item costing. During the meeting WEPCO quoted a cost of $18,000,000 for the implementation of this modification. This was based upon the following information:

INSTALLATION OF DIESEL-DRIVEN AFW PUMP

Includes:
1. Two diesel-driven AFW pumps (one/unit)
2. Associated Instrumentation and controls, starting system, fuel oil system
3. Construction of Seismic Class I and tornado-missile resistant design building

Basis:
1. A two-loop W plant installed two additional motor-driven AFW pumps in existing seismic building in 1979. Cost was $16,000,000.

2. WEPCO recently estimated cost of installation of 3rd diesel generator in a Seismic Class I, tornado-missile resistant building for ~$7,000,000.

3. Another two-loop W plant is installing two new emergency diesel generators in a new building - estimated cost is about $20,000,000.

From this it may be observed that the costs being quoted are based upon the presumption, it costs this much to do this, therefore it will cost a similar amount to accomplish this modification. The following breakdown of costs has been provided by United Engineers and Constructors (UEC).

COST ESTIMATE DIESEL-DRIVEN AFW PUMP

Construction Costs:		
Structure:	Labor 23065 m-hr @ $18.90	$ 435,960
	Materials	174,020
Piping:	Labor 11990 m-hr @ $21.25	254,820
	Materials	139,460
Equipment (Diesel Driven Pump, etc):		
	Labor 820 m-hr @ $21.90	17,960
	Materials/equipment	487,600
	Subcontractor	42,000
Electrical:	Labor 5128 m-hr @ $ 21.10	108,210
	Materials/equipment	120,680
Misc. Supp:	Labor 4685 m-hr @ $18.45	86,460
Factors: Congestion, accessibility, interferences		
	Labor 34750 m-hr @ $21.25	738,450
		$2,605,640

We believe that the Case Study estimates have been developed in a logical and rational manner, unfortunately there is no way at this point to really compare the two inputs since WEPCO only provides a "bottom line." Given UEC's experience we are at a loss to adequately explain the differences.

<u>Wind - Diesel Generator Exhaust Supports (MOD 119)</u>: If one subtracts the $10,000 cost attributed to testing and submittals by WEP, then the $15,750 cost reported by UEC does not compare that unfavorably with the $20,000 estimated by WEP. However,

there are no details upon which to base a comparison at this time.

2.2.3 Summary

It is impossible to adequately compare the cost estimates for the Case Study and NSAC-113 due to the lack of detail in the EPRI/WOG analysis. They rely heavily upon comparison with "similar" work at Point Beach or other utilities and include significant costs for in-house planning and review, but they do not provide sufficient information for an independent assessment of the applicability of that other work to the modifications proposed in the Case Studies. If there is interest in resolving these differences that can be done, but it will require significant resources on the part of both NRC/Sandia and EPRI/WOG.

2.3 Value-Impact Analysis

Because EPRI/WOG has used a somewhat different method for the value-impact portion of the work, it is not surprising that they get different results. The following paragraphs provide some comment on several specific items.

Inclusion of installation and O&M doses in the "offsite cost only" case. (Page 10-6, third paragraph) In our view there is a better argument for excluding these doses, in this case, than for including them. Our reasons are as follows: In this case the regulator is making a decision based upon the effects on the health of the public who are exposed involuntarily to the radiation risks. The "installation and O&M doses" are incurred voluntarily by persons who are aware that there is some risk, but are willing to accept the risk in return for the advantages obtained by accepting it (wages). To equate these voluntary and involuntary risks is unsatisfactory in any circumstance; it is quite incorrect in this particular case.

Lumping of several "modifications" into a single "alternative". (Page 10-6, fourth paragraph) The disadvantages of this procedure were recognized by SNL and UCLA early in the program, but it was also recognized that there were insufficient resources to examine systematicallly the effects of changing the components and sequencing of the individual modifications in six case studies.

Choice of discount rate. (Page 10-8, last paragraph) We chose to use five (5) percent as the main case because ten (10) percent as a discount rate in a non-inflationary economy, would have been unrealistic. It should be noted that apart from this one exception, the UCLA methodology used in the case studies followed the NRC "rules" in every respect. However, in the Summary Report on the UCLA work on value-impact analyses[27] there is an extensive discussion of alternative approaches.

Treatment of "installation and O&M doses" as "values". (Page 10-9) In the UCLA methodology for the case studies these doses were treateed as "negative values" rather than "positive impacts" simply because it was our understanding that this was the approach preferred by NRC. We agree that there is, in principle, just a good a case for treating the as "positive impacts." Clearly if the latter course were adopted the numerical values for the various V/I ratios would be different; the concept of Specific Net Benefit, which was developed in the Regulatory Analysis, goes some way toward reducing these differences.

Double Counting of lost plant investment. (Page 10-14) In our view the UCLA methodology does not, in general, represent double counting. In the first ten years after loss of the plant the utility has got to make good the lost capacity, unless it has a large amount of excess capacity of its own. The cost of replacement power will consist of: (i) The differential fuel cost, as between nuclear and fossil fuel; and (ii) An element which reflects the capital charges of the utility supplying the replacement power. In most "power pool" arrangements this second element is only omitted for short term duration (of order of 1 hour) replacements in emergencies.

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