Attachment C #5

FINAL DRAFT FINAL DRAFT

SUPPLEMENTAL ANALYSES

and

COMMENTS/RESPONSES TO EPRI/WOG ANALYSIS

of

DECAY HEAT REMOVAL RISK AT POINT BEACH

David M. Ericson, Jr.
ERC International
Albuquerque, New Mexico

For

Sandia National Laboratories
Albuquerque, New Mexico

March 30, 1988

FINAL DRAFT

FINAL DRAFT
SUBJECT TO REVISION
Do Not Distribute Without
Prior Approval of Author

CONTENTS

# SUPPLEMENTAL ANALYSES

# AND

# COMMENTS/RESPONSES TO EPRI/WOG ANALYSIS OF DECAY HEAT REMOVAL RISK AT POINT BEACH

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, summary lists of questions or discussion topics are included. Thus, this document provides a vehicle for subsequent technical exchanges with EPRI/WOG.

## 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 are: 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 frequency for these three sequences of 8.4E-6/rx-yr or a

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.<br>CCW Suc Crit.<br>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<br>Operator Action |
| $S_2MD_1D_2$ | 8.7E-6 | 9.5E-8 | SBLOCA Freq.<br>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<br>Alt to 1 PCRV |
| $T_2MQD_1D_2$ | 6.6E-7 | 4.1E-8 | Rel Valve LOCA<br>CCW Suc Crit |
| $S_2MXD_1$ | 5.7E-7 | 1.0E-8 | SBLOCA Freq.<br>CCW Suc Crit |
| $T_5MLE$ | 9.1E-7 | 1.3E-8 | DC Bus X-conn<br>MFW Recovery |
| $T_4MLE$ | 6.2E-7 | N/A | Loss of AC Bus does not trip |
| $T_2MLH_1$ | 2.0E-3 | 1.0E-7 | Operator Action<br>MFW Recovery |
| $T_1QD_1D_2$ | <1.0E-8 | 1.2E-7 | Rel Valve LOCA more likely |
| LTSB | 3.6E-6 | 5.4E-7 | |
| | ------ | ------ | |
| | 1.34E-4 | 2.56E-6 | |

reduction 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 for NUREG-1150[3]. 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 for NUREG-1150[4] 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, it is not obvious how the claimed reduction comes about. As noted above, the majority of the reduction for the $S_2$ sequences comes from reduction in $S_2$ frequency, while the CCW dependency only contributes about 3-10% of the reduction, depending upon the particular sequences examined.

In summary, there are several issues which need to be addressed:

1) What specific sequences were affected by the revision in the analysis?

2) What is the technical basis for removing the CCW dependency other than the statement, "A review by WEP found that CCW is not required for HPI operation in the injection mode since CCW provides seal rather than bearing cooling?" Other PRAs, e.g., Surry and Sequoyah have noted that CCW is required for seal cooling and lube oil cooling and have required successful seal cooling as a prerequisite for HPI success. Such criteria should be retained unless there is unequivocal evidence that cooling is not required.

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[7] 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

---

* 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.

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 because of the lack of "hard data" and the often subjective nature of the analysis. In the author's opinion, the general approach of the EPRI/WOG study is to adopt the most favorable (optimistic) HRA values whenever possible, often without adequate substantiation.]

1.1.2 Loss of Offsite Power

For the loss of offsite power (LOSP) transients $T_1$MLE 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 reanalysis 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, the listing provides no 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) it does appear that EPRI/WOG treated the new battery as a "recovery" action although that is not explicitly spelled out. Given that the third battery now exists, it would be appropriate to include its use in any analysis.

The EPRI/WOG report indicates that the sequence $T_1QD_1D_2$ will "appear" because there is an increased liklihood of a relief valve LOCA. In this sequence AFW succeeds, however in Appendix B of NSAC-113 all the sequences listed for $T_1$ involve $T_1M$-Q and some sort of AFW failure. Therefore, we are unable to comment on the validity of their observation.

1.1.3 Loss of Feedwater Transients

For the loss of feedwater (LOFW) transients $T_2MQH_1'H_2'$, $T_2MLE$, $T_2MQD_1D_2$ 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 Probabililty: The EPRI/WOG study does assume 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. A W survey[8] of PORV and SRV events indicated that there were no failures of PORVs in some 163 operational openings and no SRV operational openings, therefore no failures. If there are PORV openings, then it is not expected that the SRVs receive any challenge. But 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[9], suggest that SRV set points would not be reached. However, 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[10] it was then assumed that the probability that once opened the 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 becomes 1.4E-3. If one accepts the argument that the 0.07 value is conservative for SRVs, other studies[11] 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 result 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.

In contrast, the EPRI/WOG study assumes that the PORVs are generally unblocked, but accounts for the possibility that

-----------

* 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.

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, the main area for discussion then being the value selected for operator action; where they use 1E-3/demand, SNL would use 3E-3/demand. Using the latter value would yield a $T_2QM$ multiplier of 2.7E-4, comparable to the revised approach discussed above. Therefore, it is agreed that in a plant specific study the probability of relief valve LOCA could be lower than 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.

Finally, we have been unable to ascertain from the information presented precisely how the alternative to 1 PORV is implemented/quantified. It is understood that additional venting to containment is assumed (DC operated vent valves). As noted above, the bases for the CCW success criteria need to be more fully explained, although it is also noted that this does not have a major effect upon the results, the principal impact comes from the reduction in the event Q value.

1.1.4 Other Transient Sequences

For the remaining transients, $T_3QH_1'H_2$, $T_3QD_1D_2$, $T_4MLE$, and $T_2MLF$ the EPRI/WOG report argues either that they do not, or cannot, occur or that they are significantly reduced by the availability of DC cross-connects and main feedwater recovery.

<u>Miscellaneous $T_3$ Sequences</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[9], since no reference is cited. Unfortunately, this seems to be a situation in which the position is taken, if it hasn't happened, and analysis says it won't happen, then it won't happen. While PRAs are built upon experience to the maximum extent possible, it does not appear reasonable to 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 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[12] 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 $T_4$MLE, the EPRI/WOG study simply states that an evaluation by WEP indicates that the 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 compilations of data. If independent assessment of NSAC-108[13] indicates that the data is valid 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, it is presumed that the 2.2E-2 is a combined failure to start and run for one hour. On this basis the NSAC-113 value is 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. 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. 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[14] 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 value into the study would reduce the 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.[15]] 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 better explanation by EPRI/WOG of their long term cooling analysis. This yields a value of 9.9E-6/rx-yr for the LTSB contribution.

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 External Events

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

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 | 1.3E-6 | SBLOCA Freq. |
| $T_3QD_1D_2$ | 4.6E-6 | 6.6E-7 | Rel Valve LOCA |
| $T_2MLE$ | 6.6E-7 | 6.6E-7 | None |
| $T_2MQD_1D_2$ | 6.6E-7 | 9.4E-8 | Rel Valve LOCA |
| $S_2MXD_1$ | 5.7E-7 | 8.8E-8 | SBLOCA Freq. |
| $T_5MLE$ | 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 |
| $T_1QD_1D_2$ | <1.0E-8 | <1.0E-8 | None |
| LTSB | 3.6E-6 | 9.9E-6 | $T_1$ Freq<br>DG-LF Value |
| | ------ | ------ | |
| | 1.34E-4 | 3.03E-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 |
| | ------ | ------ | ------ |
| | 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.

(upgraded) emergency batteries, alternate water sources for the RWST, and recovery actions following the earthquake. Each of these is discussed briefly below.

The Hazard Curve: SNL does not agree with this modification, as it has no 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 is realistic.

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. Several questions remain to be answered. Are the new batteries full-station emergency batteries or are they dedicated to the diesel generators and perhaps a few specific pieces of instrumentation? This latter situation seems to apply. 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.[15]]

<u>Alternate Water Sources for the RWST</u>: The EPRI/WOG reanalysis takes credit for manually aligning other (presumably undamaged) water sources to replace the RWST, based on: a) an EPRI study (no reference) showing 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.

<u>Recovery</u>: 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.

<u>Summary</u>: 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. We do not concur with the other changes suggested.

1.2.2 Fire (Comments prepared from material by T. Wheelis/SNL)

The first area of concern deals primarily with the EPRI/WOG statement on page 6-4, NSAC-113, "The NRC Case Study scenarios focused on transient combustible fires." This erroneous statement has been made repeatedly by industry reviewers. In response, SNL has stated, also repeatedly, that this is not the case. The assumption in the fire analysis was that the two fire sources used were representative of the cables (in situ) or transient combustibles found in a particular location. The idea being that one can not analyze every possible case, so use a bounding approach. There currently is no way to say exactly how much or where a fire source will be in a room. By the same token, there is no way to know where an electrical cable might ignite. However, based upon historical data, fires at nuclear power plants have been caused by both transient combustibles and self-initiated cable fires. Our selection of fire sizes was used to bound these fire sources. In addition, the historical fire frequency data for given fire areas certainly indicates that fires do occur and thus would seem to imply that there is "some" fire source present in the area or room. It will be noted that in the fire analysis (NUREG/CR-4458, Appendix D, page D-19) the fire frequency for the particular room, AFW pump room in this case, was derived by considering the in situ fuel loading, i.e., cabling, in relation to the total fuel loading in the building. [SNL does not understand how reviewers can continually assert that the emphasis was upon transients when the analysis clearly and unequivocally states the generic frequency data was used.]

The second area of disagreement between the studies is in fire frequency. As noted, SNL used generic data for auxiliary building fires, and using fuel loading information provided in the Point Beach Appendix R submittal, developed a frequency for the particular room. EPRI/WOG used specific event data to develop their frequencies. We also note that NSAC-113 draws heavily upon some portions of the Limerick PRA[16]. That should be done with caution since in several instances the Limerick PRA reports reduced liklihood of fires based on the argument (engineering judgement) 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 2.7 times the NSAC-113 value and for the switchgear room only about 1.4 times greater. Given the state of the art of fire PRA at the time of the original study, these differences are not that important.

A third area of significant disagreement deals with 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. It is difficult to comment on the validity of the data since it is not publically available. However, given the nature of the DOE research and production complex, we suspect that the data reflects incidents at the processing plants (Rocky Flats, Pantex, etc.). While we certainly agree that additional data is desirable, it is not clear that suppression system failure probabilites for processing plants and nuclear power reactors are comparable. That is, the processing plants probably have more stringent fire protection systems requirements (eg., more periodic testing and maintenance) than nuclear power plants.

----------

*The comment on Table D-11 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.

Similarly, the processing rooms are probably much smaller than the fire zones at the power plants, so that one might have suppresion system success for small rooms, but not necessarily large rooms. The remaining point is that new data should be factored into the existing data base, not used in isolation (simply because it provides a "better" result). The data from the Millstone PRA was based upon inspector testing data at nuclear power plants by the "American Nuclear Insurers Group" (>60 data points). Therefore, if the DOE data is really comparable, it should be combined with the existing data and new reliabilites derived. If such an analysis leads to an improved estimate of reliability then it should be used. However, until the applicability of the unpublished DOE data is demonstrated and the combined analyis is accomplished, it is recommended that the SNL values for Halon system reliability be used. [During some recent conversations with A. Buslik of the NRC staff, he indicated that there was some information available that suggests that the potential for common-mode failures of Halon suppression systems exists. Maybe he actually had some data, that point is not clear. This should be followed up since if there are such common-mode failures the SNL estimates may even be optimistic.]

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, especially for a fire in the AFW pump room. In this case you could have a fire in the room where you were trying to manually align a pump. It would appear that the key to using a lower value would be 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. Unlesss very specific and detailed HRA results are available, SNL recommends retaining the 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 is consistent with generic goals of the study. In contrast, EPRI/WOG cites a pipe break correlation by Thomas[17] 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 rational 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 reductions of at least an order of magnitude from the 2E-2 originally used taking this sort of scaling approach.

A more extensive discussion of this particular event 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. This assumes without proof that 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 study will consistently take the most optimistic view. Unfortunately, this is usually done without much documented analysis, relying heavily upon engineering judgement 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. SPECIAL 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[19] 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[17] 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.

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 17) 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 probabililty modeling must recognize this."

Therefore, it would be appropriate for EPRI/WOG to explain how their expresion was derived and how they established its applicability to this issue.

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. 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, <u>and its validity here remains to be demonstrated</u>, 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[19], 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, EPRI/WOG should provide the reasoning behind 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. 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.[20], 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 all LWRs together their results may be summarized as follows.

| 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 that 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 <u>no breaks</u> of significance 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. Therefore, in a more precise, plant-specific study, a non-LOCA pipe break frequency less than the 2.2E-2/yr used in the Case Study is probably justifiable, although a value greater than the 3.75E-5/yr reported by EPRI/WOG would be expected.

2.1.3 Summary

The questions which need to be addressed in discussions with industry are:

1. How did EPRI/WOG derive/develop their version of the Thomas correlation?
2. How was the applicability of this correlation to this study established?
3. What is the basis for limiting consideration to one 3-foot section?

## 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.

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 application 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.

<u>Internal 8 - Spare RHR Pump (MOD 816)</u>: NSAC-113 notes that the principal difference results from provision of a different power arrangement in response to Enforcement Information Notice (IEN) 86-79. While it is reasonable to state that costs will be higher, it is <u>not</u> reasonable to fault the Case Study for not including a requirement which was not imposed until after the technical effort was completed.

<u>Internal 9 - Diesel-Driven Auxiliary Feedwater Pump (MOD 817)</u>: NSAC-113 states that, "The principal difference is that piping could not go through the non-seismic turbine building. The WEP estimate assumes construction of a new seismic building 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

.
.
.

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, <u>but not connected to the existing plant turbine hall.</u> (Emphasis added)

.
.
.

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 necessarily 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. One wonders why? The second part of the comment is disturbing 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 spent fuel 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 staff?

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. It is not at all clear why "iteration" would be required on a task as straight forward as the shield wall.

2.2.2 Specific Comments

Internal 9 - Diesel-Driven Auxiliary Feedwater Pump (MOD 817): WEP estimates costs at $8,000,000 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 that those used by the Case Study and because WEP uses costs for a Seismic I building and the Case Study did not. The

Case Study cost estimates were generated using the general method outlined in NUREG/CR-3791[21], the Handbook for Cost Estimating, information from the Energy Economic Data Base[22] and the Technical Assessment Guide[23]. This information was augmented with local cost experience gathered during the site visits. In contrast, the EPRI/WOG approach was to use "an experienced WEP cost estimator" to review and revise the estimates. It would appear, given the "bottom line" number reported, $8,000,000 versus $2,606,000, that the WEP estimates are much coarser than those developed by United Engineers and Constructors (UEC) for the Case Study. Particularly, since the WEP estimator started with the published UEC information which only shows aggregate costs for labor and materials. Although UEC was not required under their contract with Sandia to provide the details of the costing (unit costs, hourly rates, etc,) that information has been requested in order to have a complete package to compare with any EPRI/WOG details that become available during the planned discussions. In the Case Study the indirect costs vary somewhat with alternatives. For example, for Alternative 1 the indirects are ~66% of the directs, while for Alternative 3 they are ~70% of the directs, so that the ratios of total cost to direct cost range from 1.66 to 1.70. Apparently a similar variation exists in the WEP estimates since the ratios of total cost to direct cost vary from 2.21 to 2.53 for the estimates provided in Table D-1, NSAC-113. It may be noted that the indirects in NSAC-113 are approximately 1/3 greater than those in the Case Study, but there is no explanation for the increase. Similarly, there is no explanation for the increase in direct cost, i.e., how much piping was added, how much additional concrete and steel, etc.

<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 $20,00 estimated by WEP. However, there are no details upon which to base a comparison at this time. Added information is being sought from UEC.

2.2.3 Summary

Based upon the preceeding discussions, the following issues need to be addressed with industry.

1. Did the WEP estimator "back out " to 1985 costs or are these 1987 figures in NSAC-113?

2. Did the WEP estimator use the Bill of Material called out in Appendix J, or did he just apply some arbitrary "factor" to the Case Study numbers?

3. Were man-hour estimates examined individually or was some arbitrary "factor" applied?

4. How was the applicability of prior work at Point Beach established? Example: battery installation.

5. The basis for cost increases presumably presented in Appendix D, Table D-11 is inadequate for any meaningful comparison. Can EPRI/WOG enumerate and quantify the differences more precisely?

6. How did EPRI/WOG come to the conclusion that added piping runs were required?

7. What is the basis for <u>increasing</u> costs for a Seismic I structure above those reported in the Case Study?

8. Are the installed systems really so inadequately documented that locations of buried piping and cabling are unknown?

REFERENCES

1. EPRI/WOG Analysis of Decay Heat Removal Risk at Point Beach, NSAC-113, Science Applications International Corporation and Westinghouse Corporation for Electric Power Research Institute, October 1987.

2. Shutdown Decay Heat Removal Analysis of a Westinghouse 2-Loop Pressurized Water Reactor, NUREG/CR-4458, SAND86-2496, Sandia National Laboratories, March 1987.

3. Analysis of Core Damage Frequency From Internal Events: Sequoyah, Unit 1, NUREG/CR-4550/Vol 5, SAND86-2084, Sandia National Laboratories, February 1987.

4. Analysis of Core Damage Freuency for Internal Events: Surry, Unit 1, NUREG/CR-4550/Vol 3, SAND86-2084, Sandia National Laboratories, November 1986.

5. Oconee PRA, A Probabilistic Risk Assessment of Oconee Unit 3, NSAC-60, Nuclear Safety Analysis Center, EPRI, June 1984.

6. Shutdown Decay Heat Removal Analyis Plan, Letter Report, Sandia National Laboratories, August 1984.

7. Review and Evaluation of the Indian Point Probabilistic Safety Study, NUREG/CR-2934, SAND82-2929, Sandia National Laboratories, December 1982.

8. Probabilistic Analysis and Operational Data in Response to NUREG-0737, Item II.K.3.2 for Westinghouse NSS Plants, WCAP-9804, Westinghouse Electric Corporation, February 1981.

9. Personal Communication, D. Paddleford, Westinghouse, and D. Ericson, ERCI, March 28, 1988. Best estimate analyses by Westinghouse have minimal circulation outside the company.

10. Interim Reliability Evaluation Program Procedures Guide, NUREG/CR-21728, SAND82-1100, Sandia National Laboratories, January 1983.

11. Reactor Safety Study Methodology Applications Program: Oconee #3 PWR Power Plant, NUREG/CR-1659(2 of 4), SAND80-1897(2 of 4), Sandia National Laboratories, May 1981.

12. Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Operations, NUREG/CR-1278, SAND80-0200, Sandia National Laboratories, August 1983.

13. The Reliability of Emergency Diesel Generators at U. S. Nuclear Powe Plants, NSAC-108, Electric Power Research Institute, September 1986.

REFERENCES(Continued)

14. "Common-Cause Failure Data: Experience from Diesel Generator Studies," Nuclear Safety, Vol 26, No 3, May-June 1985, pp 305-313.

15. Letter, Review of "EPRI/WOG Analysis of Decay Heat Removal Risk at Point Beach, (NSAC-113), Final Report, Octobar 21, 1987," P. R. Davis to P. Bohnert, ACRS, January 11, 1938.

16. Severe Accident Risk Assessment Limerick Generating Sttion, Report #4164, Philadelphia Electric Company, April 1983.

17. "Pipe and Vessel Failure Probability," Reliability Engineering, Vol2, 1981, pp 83-124.

18. Loss of Main and Auxiliary Feedwater Evwent at the Davis Besse Plant on June 9, 1985, NUREG-1154, USNRC, July 1985.

19. "Internal and External Flood Failure Model," Chapter 10 of The Impact of External Events, Fire, Internal Flood on Nuclear Power Facilities, Notes from ACTA Consulting Engineers and Applied Scientists, 1984.

20. Pipe Break Frequency Estimation for Nuclear Power Plants, NUREG/CR-4407, EGG-2421, EG&G Idaho Inc., May 1987.

21. A Handbook for Cost Estimating, NUREG/CR-3971, ANL/ESS-TM-205, Argonne National Laboratory, October 1984.

22. Energy Economic Data Base (EEDB) Program, Phase VII Update, United Engineers and Constructors for Oak Ridge National Laboratory, 1984.

23. Technical Assessment Guide (TAG), EPRI P-2410-SR, Electric Power Reserch Institute, May 1982.