Benefit Cost Analysis of Enhancing Combustible Gas Control Availability at Ice Condenser and Mark III Containment Plants

Draft Letter Report

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LIST OF ACRONYMS

AC	alternating current
AFW	auxiliary feedwater
BEIR	Biological Effects of Ionizing Radiation
BLS	Bureau of Labor Statistics
BNL	Brookhaven National Laboratory
BWR	boiling water reactor
CDF	core damage frequency
CPEF	conditional probability of early failure
DC	direct current
DCH	direct containment heating
DG	diesel generator
DW	drywell
EF	early failure
FSAR	Final Safety Analysis Report
IPE	Individual Plant Examination
IPEEE	IPE for External Events
LERF	large early release
LF	late failure
LOCA	loss of coolant accident
LOSP	loss of offsite power
MAAP	Modular Accident Analysis Package
NF	no failure
PDS	plant damage state
PRA	probabilistic risk assessment
PWR	pressurized water reactor
RCIC	reactor cooling isolation system
RCP	reactor coolant pump
RCS	reactor coolant system
S	scrubbed
SBO	station blackout
SDP	Significance Determination Process
SNL	Sandia National Laboratories
SP	suppression pool
SSW	standby service water
TMI	Three Mile Island
US	unscrubbed

1. BACKGROUND

SECY-00-0198 [1] presented a risk-informed alternative to the current regulation in 10 CFR 50.44 that deals with the threat of combustible gases to the integrity of the containment in light-water reactor nuclear power plants. One of the risk insights developed in SECY-00-0198 indicated that station blackout (SBO) accident sequences represented a threat to containment integrity in BWR plants with a Mark III containment and PWR plants with an ice condenser containment. These pressure-suppression containments were mandated under 50.44 to install combustible gas igniters that would burn the hydrogen evolved via the metal-water reaction during severe core melt accidents. The igniters are designed to burn the evolved hydrogen at relatively low concentrations and thus reduce the potential for large deflagrations or detonations that could challenge containment integrity. However, the igniters need AC power to operate and would not be available in an SBO accident. Thus, enhancements that would allow combustible gas control during SBO accidents could reduce the risk from combustible gases. The issue to be analyzed is whether such enhancements would be cost beneficial, i.e., whether the averted risk, evaluated in terms of the expected value of averted costs, would be greater than the direct cost of implementation of the enhancement.

Under Project JCN W-6224 Brookhaven National Laboratory (BNL) is providing an estimates of the benefit values associated with making enhancements to the combustible gas control systems in PWR plants with ice condenser containments and BWR plants with Mark III containments. In addition to calculating benefits based on point estimates or mean values, BNL has also been asked to provide insights into the uncertainty of the estimates provided. This estimate of benefit values is the subject of the present report. The enhancement would make combustible gas control available during SBO accidents, and this could be accomplished in a number of ways. BNL is not considering the implementation costs of any enhancements (these are calculated elsewhere), and therefore this report is silent on the particular means by which the combustible gas control will be accomplished.

Based on the Statement of Work, this report discusses what averted costs should be included in the analysis and how they should be treated. Avoided (offsite) person-rem and avoided (offsite) property damage are mentioned as potential benefits in the Task Action Plan for Generic Safety Issue 189. The Statement of Work indicates that the analysis should include all types of averted costs in accordance with NUREG/BR-0058, Rev. 3 [2] and the estimation and evaluation of values should comply with Section 4.3 of NUREG/BR-0058, Rev. 3.

2. APPROACH

This report provides an estimate of the benefit accrued from enhancing the currently installed combustible gas control systems in PWR nuclear power plants with ice condenser containments and BWR plants with Mark III containments. The current systems are not available during SBO accident sequences, and the enhancement whose benefit is being estimated would allow combustible gas control during SBO sequences. The analysis presented here is concerned only with the value of the benefit obtained from such an enhanced system, not the details involving what changes, additional systems, etc. are implemented to achieve the enhancements. Note that this means that any negative benefit associated with the installation of the enhancement, such as worker exposure during installation, is not considered here, and is dependent on the particular means chosen to implement the enhancement. It is expected that items such as worker exposure would be included in the estimates for the cost of the enhancement, which is being estimated elsewhere. The benefit calculated here is expressed in terms of the risk averted as a result of the enhancement, stated in terms of current dollars.

The work scope of this project does not allow for a new integrated analysis, but instead calls for estimates based on previously obtained PRA results from a number of different existing studies. This also means that for the evaluation of uncertainty in the estimate no integrated uncertainty analysis is possible. However, some uncertainty information can be obtained from existing PRA models of the relevant plant types.

In terms of current dollars the averted risk for the enhancement in question, where risk equals likelihood times consequences, is calculated for this study using the following steps:

1. The frequencies of the affected accident sequences are determined in terms of frequency per reactor year. For the combustible gas control enhancement the applicable sequences are the SBO sequences.
2. The change in conditional containment failure probability for each relevant containment failure mode as a result of the enhancement is determined.
3. The consequences associated with each containment failure mode are determined. If the consequences are in terms of person-rem (such as for health effects) for a population density estimated for a previous year, the person-rem are adjusted by a factor which reflects the estimated change in population density from the year of the calculation to the year 2000. The person-rem are then monetized by a dollar/person-rem factor. If the consequences are in dollars estimated for a previous year (such as for property damage) the dollars are converted to current dollars with an appropriate inflation factor.
4. The product of the conditional containment failure modes times their consequences without the enhancement are summed, as is the product of the conditional containment failure modes times their consequences with the enhancement in place.
5. The sum obtained with the enhancement in step 4 is subtracted from the sum without the enhancement. The difference is multiplied by the frequency determined in Step 1. The result is the averted risk, in terms of dollars per reactor year.

6. A present value calculation is performed using the result of Step 5, and the remaining years of assumed plant life, to obtain the benefit for the life of the plant in terms of current dollars.

The benefit analysis carried out here are in accordance with the guidance on estimation of values provided in NUREG/BR-0058 [2] and in NUREG/BR-0184 [3]. In particular, in conformance with Section 4.3.2 of NUREG/BR-0058, the estimation of value attributes related to the enhancement considered here include:

- reductions in public and occupational radiation exposure,
- averted offsite property damage, and
- averted onsite impacts

Additional potential value attributes listed in NUREG/BR-0184 are: enhancements to health, safety, or the natural environment; savings to licensees; savings to NRC; savings to State, local, or tribal governments; improved plant availability; promotion of the efficient functioning of the economy; and reductions in safeguards risk. These were not considered in the present analysis because they were deemed to be either not applicable or would have a negligible impact on the results.

In the present analysis, again as called for in NUREG/BR-0058:

- changes in public health and safety from radiation exposure and offsite property impacts are examined over a 50 mile distance from the plant site,
- the recommended dollar conversion factor of $2000 per person-rem is used and used only to capture the health effects attributable to radiological exposure,
- offsite property damage consequences are addressed separately and treated as an added factor in the value assessment,
- estimated values are expressed in monetary terms whenever possible and expressed in constant dollars from the most recent year for which price adjustment data are available,
- all values and impacts are expressed on a present worth basis for lifetime benefits, and
- a discount rate of 7% is used for the present-worth calculation, with a sensitivity analysis at a 3% discount rate.

NUREG/BR-0058 also calls for value estimates to be based on mean or 'expected value' calculations when possible, and to consider uncertainties. However, NUREG/BR-0058 also recognizes that the level of detail available from data sources may not allow expected value estimates to be used, and allows sensitivity analyses, including hypothetical best and worst case values, to be used in lieu of uncertainty analyses. The enhancement under consideration here carries with it no potential reduction in core-damage frequency, only in containment failure probability. The emphasis of the evaluation is on containment performance, i.e., the reduction in the conditional containment failure probability when combustible gas control is available during SBO events. Estimating changes in containment failure probability are especially uncertain and involve sparse data. In addition, the analysis here relies on calculations from previous analyses carried out for other purposes. Therefore, the benefit estimates calculated here are not always based on expected value, and use some sensitivity calculations as well as some previously obtained uncertainty results.

It should also be noted that NUREG/BR-0058 calls for a safety goal evaluation, using certain safety goal screening criteria relative to the enhancement, under some situations. However, as stated at the end of Section 3.3.2 of NUREG/BR-0058, "...the safety goal screening criteria described here do not address issues that deal only with containment performance. Consequently, issues that have no impact on core damage frequency (CDF) (delta CDF of zero) cannot be addressed with the safety goal screening criteria." No safety goal evaluation has been carried out in the present analysis.

As noted above, the results presented in this report were calculated based on information gathered from various existing analyses. The severe accident progression scenarios, including conditional containment failure probabilities, are based primarily on the NUREG-1150 [4] work, including the descriptions and values reported in the NUREG-1150 supporting documents for the Sequoyah [5] and the Grand Gulf [6] analysis. The conditional probability of early failure (CPEF) of containment from NUREG/CR-6427, "Assessment of the DCH Issue for Plants with Ice Condenser Containments" [7] was used to for a sensitivity case for the ice condenser estimates. Finally, NUREG/CR-xxxx, "Basis Document For Large Early Release Frequency (LERF) Significance Determination Process (SDP)" [8], which summarizes relevant NUREG-1150 information, was employed to establish the accident progression used for the BWR Mark III estimates. It should be noted that all these references, with the exception of Reference 7and Reference 8 are included in NUREG/BR-0184, the Regulatory Technical Analysis Handbook, as appropriate references for value impact analysis. References 7 and 8 are too new to be included in NUREG/BR-0184. In addition to the NUREG-1150 SBO frequencies, the frequencies from the Duke Power PRAs contained in Reference 9 were used in the uncertainty considerations. SBO frequencies from the NRC's SPAR models, as well as frequencies reported in the Individual Plant Examinations (IPE) and in the IPE for External Events (IPEEE) for the plants are also discussed. The value of offsite property damage and offsite person-rem are taken mostly from an earlier BNL study, NUREG/CR-6349 [10]. The exception are some of the values of offsite person-rem for the Duke Power plants, which were extrapolated from Reference 9. Discussion provided on the values of onsite health costs and onsite property damage costs are based on the information provided in Burke and Aldrich [11], and in NUREG/BR-0184 [3]. Updates of population densities are based on population projections found in the Final Safety Analysis Reports of the plants examined, not on actual current population statistics.

The remainder of this report is organized as follows: Section 3 below provides a discussion of averted costs, i.e., benefits of providing means (such as installing a backup power supply for the hydrogen igniters) to allow combustible gas control to function during SBO accidents. The various categories of applicable costs, including offsite health costs, offsite property damage costs, and the onsite costs, including employee health costs and onsite cleanup and decontamination costs for accidents that fail containment, are discussed and summarized. Sources of data for the various categories of costs are identified and referenced, where relevant.

Section 4 presents the results obtained for a number of PWR ice condenser plants, based on existing studies. An example calculation is provided, along with the results from a number of additional calculations which provide insight into the uncertainties involved in the benefit estimates.

Section 5 presents similar results for BWR Mark III plants, with Grand Gulf as the Mark III surrogate. In addition, some of the Grand Gulf results are extrapolated to another BWR Mark III plant in this Section to obtain a more generic estimate of the benefit that could be obtained for BWR Mark III plants from a combustible gas control system that is operational during station blackout.

In Section 6 the results obtained are discussed, and some reasons for the differences between the PWR ice condenser results and the BWR Mark III results are provided.

3. DISCUSSION OF AVERTED COSTS

The averted costs arise from the averted consequences of reactor accidents. In general, there are several categories of offsite consequences that follow the occurrence of an accident that begins with core melt and progresses to containment failure and the release of radioactive material from the reactor core to the environment: (1) acute effects of large radiation doses generally in excess of 200 rem to offsite populations in the initial phases of the release that can lead to early health effects (early fatalities or early injuries), (2) chronic effects of lower radiation doses that can lead to cancer induction over long periods of time and cause latent cancer fatalities or injuries, and (3) the offsite costs of emergency response and long-term protective actions that are taken to protect the public from radiation.

The risk metrics used to estimate offsite acute and chronic health effects are early (or prompt) fatalities and early injuries and latent cancer fatalities and injuries, respectively. Acute health effects arise soon after exposure via the inhalation, cloudshine, and groundshine pathways. As noted above, acute doses in excess of about 200 rem whole body can lead to early fatality. Chronic effects of long-term exposure are due to three pathways: groundshine from living on contaminated land, inhalation from breathing resuspended radioactive material, and ingestion of contaminated food or water. Dose models embedded in consequence codes predict the dose to a population living in a certain spatial segment based on the characteristics of the release (magnitude, timing, and energy), sampling over the weather at the site, and on any counter-measures that are taken. Dose-response models then are used to predict the early fatalities and latent cancers based on the extent of exposure.

The counter-measures that are taken to protect the offsite public from the released material involve costs that depend on the nature of the protective measures and their duration. The sum of these costs are usually called the "offsite property damage costs." In the early stages of an accident, costs are associated with emergency evacuation and relocation. These will depend on the number of people affected and the duration of the emergency period. Evacuated individuals will generally remain relocated and will not be allowed to return until the projected groundshine dose is below the protective action guideline value for at least the duration of the emergency phase. In the longer term, people will remain relocated and thus continue to incur costs associated with temporary relocation, depending on the doses from the resuspension inhalation and groundshine pathways. Over a time period of several years following the release, a decision has to be made whether contaminated property, such as farmland and non-farm areas, should be decontaminated or permanently interdicted. The consequence code MACCS, for example, models three successively higher levels of decontamination, each associated with respectively higher costs. If the decontamination efforts plus natural decay cannot reduce the projected long-term dose to an individual below a specified value, or the cost of decontamination exceeds the value of the farmland or non-farm property, then the property or farmland is interdicted and its discounted value is added to the other offsite costs. If people must be permanently resettled because their property is condemned, further costs are added based on estimates of personal income loss and moving costs for a transitional period. Finally, costs are associated with the disposal of contaminated farm products and restrictions on crop, dairy, and meat production from contaminated farmland. Dose criteria associated with protective action

guidelines on ingestion of contaminated food are used to determine whether farm products should be discarded.

In value-impact analysis, the averted costs that are ascribed to the averted offsite health impacts are calculated based on the monetary equivalent of averted collective dose (person-rem) at the current NRC-recommended value of $2000 per averted person-rem. They are not calculated based on assigning a monetary value to the early fatality and latent cancer fatality risk metrics. The figure of $2000 per person-rem is assumed to subsume the early and latent fatalities, as well as severe hereditary effects. To obtain the total averted offsite cost (or benefit) of a proposed action, the offsite property damage costs that arise from the long-term protective actions, as discussed above, are added. It should be noted that the costs of long-term protective actions depend on the criteria selected for the allowable dose levels of long-term exposure of the affected population, i.e., there is a trade-off between a higher dose limit/lower cost and a lower dose limit/higher cost. This feature of benefit-cost analysis is discussed at some length in Reference 10.

In addition, there are also potential onsite consequences that are associated with severe accidents. Onsite consequences are not generally modeled in consequence codes, such as MACCS, and NUREG/BR-0058 cautions that particular care should be taken in estimating dollar savings derived from averting onsite costs, since values are often difficult to estimate accurately. There have been a limited number of studies which have attempted to estimate onsite costs. In particular, Strip [12] looked at the impact on worker health, including fatalities and injuries of severe accidents involving core melt and vessel breach. Burke and Aldrich [11] estimated the cleanup and decontamination costs for both degraded core accidents, such as TMI-2, and severe accidents involving vessel breach and possibly containment failure. In the latter case, it is estimated that the cost of cleanup could be significantly higher due to the additional cost of working in high-radiation environments significantly higher than those experienced at TMI-2. A "best estimate" cleanup cost of $1.7 billion (in 1982 dollars) was estimated by Burke and Aldrich for this latter type of accident, compared to half that cost for a TMI-2 type of accident. However, the discussion in Burke and Aldrich implies that the major component of the additional cost is due to the clean-up work carried out in the higher radiation environments due to vessel failure. Since combustible gas control systems cannot reduce the likelihood of vessel breach, only the likelihood of containment failure, the above difference in cleanup costs does not seem to apply for the case considered in this report. There is no explicit discussion in Burke and Aldrich on the difference between the consequences from accidents that lead to core damage but do not cause containment failure, and those that do involve containment failure.

NUREG/BR-0184, the Regulatory Analysis Technical Evaluation Handbook, does provide some data on occupational exposure that can be used for estimates possibly applicable for the case under consideration here. Section 5.7.3 of this handbook discussed the immediate dose and the long term dose workers may receive during cleanup of a severe accident. For the long term dose three accident scenarios are considered. The difference between Scenario 2 and 3 appears to be applicable for the case under consideration. Scenario 2 simulates the TMI-2 accident: 50% of the fuel cladding ruptures, some fuel melts, and the containment is extensively contaminated, but there is minimal physical damage. In Scenario 3 all fuel cladding ruptures, there is significant fuel melting and core

damage, the containment is contaminated and physically damaged, and the auxiliary building undergoes some contamination. The best estimate long term total exposure for Scenario 2 is 7,640 person-rem, while that for Scenario 3 is 19,760 person-rem. Assuming that the immediate dose is roughly the same for both scenarios, the difference in exposure between the two scenarios is about 12, 000 person-rem. It is not clear from the discussion in NUREG/BR-0184 how much of the additional exposure was due to the containment failure alone, and how much was due to the greater core damage postulated for Scenario 3, and therefore the numbers must be viewed with caution for a situation where the enhancement only addresses containment failure. However, since Scenario 3 explicitly mentions containment failure and the resulting auxiliary building contamination, it would seem that containment failure plays a significant role in the elevated exposure levels of Scenario 3.

It would also seem reasonable to assume that containment failure would have an impact on onsite property damage, since plant equipment and structures outside of containment would be contaminated in such an accident, while remaining relatively uncontaminated if the containment remains intact. Even if the plant is assumed to be unusable after a severe accident with or without containment failure, the net value of the equipment for resale or reuse at another site would be significantly impacted by contamination. Therefore, there would appear to be some benefit from averted onsite property damage when containment failure can be prevented. However, these costs may be small compared to the offsite costs in many cases. But if there is more than one unit at a site, these considerations may be important. For example, Unit 1 at TMI was put back into service subsequent to the accident at Unit 2 after a number of years. Had the TMI-2 containment failed and contaminated the other unit, the start-up of the other unit would most likely have been significantly further delayed or not happened at all. Of course, the Chernobyl accident, where there was no containment, did not prevent the other units on site from restarting eventually, but given the conditions under which these units were restarted, such a restart would have been unlikely in the United States under similar conditions.

The benefit that avoidance of containment failure can have for averting onsite costs associated with a second unit on the same site is difficult to estimate, since it can vary so widely depending on the scenario postulated. For example, replacement power costs, which are the dominant onsite costs, would only occur if it is assumed that contamination resulting from containment failure results in incremental downtime for the accident-free reactor. It is interesting to note that in the case of Three Mile Island, the accident-free unit remained unavailable for about six years even though it was physically unaffected by the accident at its sister unit. Assuming there was increased unavailability, the magnitude of the replacement power cost would be highly sensitive to when in the reactor's remaining life the accident occurred and the actual number of years of additional unavailability. Given the highly speculative nature and large uncertainties inherent in this type of cost analysis, replacement power considerations will not be included in the total averted cost estimates developed herein.

Among the plant types analyzed in this report, the PWR ice condenser plants are all dual nuclear unit sites (with the exception of Watts Bar, a single unit), while the BWR Mark III plants are all single nuclear unit sites.

Finally, it should be noted that the difference in onsite costs between core melt accidents that involve containment failure, and those that do not, does not appear to have been addressed very well in the literature. A study focusing on this difference could be helpful.

To summarize, the various categories of averted costs that are used in the analysis presented below include:

(1) Offsite Health Costs: These are based on the 50-mile radius offsite population dose (person-rem) associated with the release, conditional on the failure mode, and monetized at $2000/person-rem.

(2) Offsite Property Damage Costs: These are primarily based on the 50-mile offsite costs reported in Reference 10. The 1990 costs shown in Reference 10 have been updated to 2002 dollars using the inflation calculator provided on the Bureau of Labor Statistics (BLS) website [13].

(3) Onsite Employee Health Costs: A value of 20,000 person-rem is used here for occupational exposure for severe accidents with containment failure. A value of 8,000 person-rem is used for occupational exposure for severe accidents without containment failure. These values are based on the results found in NUREG/BR-0184 and discussed above. The person-rem are monetized at $2000/person-rem.

The present worth calculation, i.e., the discounted value of the benefit of the enhancement over the remaining lifetime of the plant (assumed to be 40 years for the plants considered, taking a life extension of 20 years into account) is calculated using the expression $\int \exp(-rt)dt$, where r is the discount rate. Calculations have been performed for the base case of r = 7% and the alternative sensitivity case or r = 3% as recommended in Section 4.3 of NUREG/BR-0058.

4. RESULTS FOR A PWR ICE CONDENSER PLANT

To carry out an estimate of averted costs in accordance with NUREG/BR-0058 and NUREG/BR-0184, risk results in terms of off-site and on-site person rem, as well as costs, are desired. This means the results from a Level 3 PRA are needed. The NUREG-1150 study for Sequoyah was an integrated study (Level 1, Level 2, and Level 3) PRA study of an ice condenser plant, and there is a significant amount of information regarding accident progression and hydrogen combustion available for Sequoyah as a result of the NUREG-1150 studies. The NUREG-1150 Sequoyah study also provides, separately, uncertainty ranges for core damage frequency (Level 1) as well as containment failure probability (Level 2). However, only internal events were examined for Sequoyah in the NUREG-1150 study. Sequoyah core damage frequency ranges due to station blackout events are presented in Table 5.2 of NUREG-1150 Volume 1 [4]. A histogram of the conditional probability of early failure (CPEF) of containment, conditional on loss of offsite power (LOSP) for Sequoyah, is shown in Figure 2.5-2 of NUREG/CR-4551, Vol.5, Rev 1, Part 1 [5]. Table 2 below summarizes the values in the reports.

Table 1 Sequoyah Uncertainty Ranges for Internal Events

	5th	mean	95th
SBO CDF frequency from NUREG-1150 (ry)	5.2E-7	1.5E-5	5.3E-5
CPEF due to LOSP from NUREG/CR-4551, Vol.5	1.3E-4	0.15	0.65

The percentile frequencies from long and short term SBO have been added to approximate a total SBO percentile frequency in the above Table.

4.1 PWR Ice Condenser Example Benefit Calculation

The benefit calculation for Sequoyah using mean values is carried out below, following the steps found at the beginning of Section 2 of this report:

Step 1 - Frequencies of SBO sequences

As indicated in Table 1, the mean SBO core damage frequency from the NUREG-1150 study for Sequoyah is 1.5E-5 per reactor year (ry) from internal events.

Step 2 - Change in conditional containment failure probability

As shown in Table 1, the mean conditional early containment failure probability due to hydrogen combustion events during SBO in Sequoyah, based on the results of NUREG-1150 is 0.15.

The benefit calculations carried out in the present report assume that the enhanced combustible gas control system will be fully effective in reducing the early failure probability to zero. There is a possibility that even if early failure is averted, the accident could proceed to late failure from over-pressurization late in the accident sequence due to steam and non-condensible gases. The presence of functional combustible gas control is not likely to make much difference to the conditional probability of late failure. However, recovery of AC power late in the accident, assuming early failure is prevented, could lead to other systems becoming functional that would allow containment to remain intact. Hence, two possibilities are analyzed: (1) there is no late failure and containment remains intact if early failure is prevented, and (2) late failure occurs even if early failure is prevented.

The pertinent conditional containment failure probability cases are summarized in Table 2.

Table 2 Conditional Containment Failure Probabilities for Sequoyah

Gas Control	Late Failure	CPEF	CPLF	CPNF
no	no	0.15	0	0.85
yes	no	0	0	1.0
no	yes	0.15	0.85	0
yes	yes	0	1.0	0

Where: CPEF is conditional probability of early failure
CPLF is conditional probability of late failure
CPNF is conditional probability of no failure

Step 3 - Consequences associated with each containment failure mode

Offsite consequences for releases representative of both early and late containment failure are presented in Table 3 below for Sequoyah. Offsite person-rem and the offsite property cost estimates are based on the data provided in References 10 for Sequoyah. These results are conditional consequences (i.e., conditional on occurrence of the release) out to 50 miles from the plant and include offsite population dose (person-rem) and offsite damage costs. The release categories for Sequoyah, i.e., source terms, are based on the results presented in the NUREG-1150 study. It is assumed that there are zero offsite consequences associated with no containment failure.

Two values for offsite person-rem are shown for Sequoyah. The 1990 values are based on Reference 10. The 2000 values have been updated based on the change in population density from 1990 to 2000 as estimated in the Sequoyah Final Safety Analysis Report (FSAR). The change is an increase of about 9%.

Two values are also shown for the offsite property damage costs. The first is taken from Reference 10 and is in 1990 dollars. The second updates the 1990 dollar values to current year dollars based on the price inflation calculator (approximately 36% over the 1990-2002 period) of the U.S. Bureau of Labor Statistics (www.bls.gov).

Table 3: Offsite Consequences (50-mile radius) of Containment Failure Releases at Sequoyah

Failure Mode	Offsite Person-rem 1990	Offsite Person-rem 2000	Offsite Health Effects ($k)	Offsite Property 1990 ($k)	Offsite Property 2002 ($k)
Early	2.8E+06	3.1E+06	6,100,000	4,800,000	6,600,000
Late	5.2E+05	5.7E+05	1,100,000	500,000	680,000

The sequence used for Sequoyah for early failure consequences is SEQ-11-2 from Reference 5 which is also used in Reference 10. This is a typical early failure sequence with about 88% of noble gases, 29% of iodine, 26% of cesium, and 21% of tellurium released. The late failure sequence used for Sequoyah is SEQ-06-1 from Reference 5 and Reference 10. This is a typical late failure sequence with all noble gases, about 8% of iodine, 1% of cesium and less than 1% of tellurium released. The discussion in Reference 5 indicates that in both these sequences the ice bed was functional and had some mitigating effect on the releases. It should be noted that the (1990) consequences reported in Reference 10 differ somewhat from those reported in the NUREG-1150 reports, even though Reference 10 is based on the NUREG-1150 analyses. This is primarily because in the NUREG-1150 study the consequence analysis was carried out using Version 1.5.11 of the MACCS code, while the consequences in Reference 10 were recalculated with Version 1.5.11.1 of MACCS. This later version explicitly incorporates the higher BEIR V risk coefficient for the latent cancer-dose relationship while the earlier version of MACCS used the BEIR III risk coefficient. In addition, a few input errors in the NUREG-1150 MACCS calculations were corrected for the recalculations of Reference 10.

Onsite health consequences are calculated assuming 20,000 person-rem occupational exposure, or $40,000k after using the $2000/person-rem factor, for both early and late containment failures, and 8,000 person-rem, or $16,000k, for no containment failure. Onsite property damage is not included as per the discussion in Section 3.

Step 4 - Summation of conditional containment failure modes and their consequences

The results of the summation of conditional containment failure modes and their consequences for the cases outlined above are shown in Table 4.

Table 4: Summation of Offsite Costs and Onsite Health Effect Costs			
Gas Control	Late Failure	Total Offsite Cost ($k) conditional on SBO	On-site Health Effects Cost ($k) conditional on SBO
no	no	1,900,000	20,000
yes	no	0	16,000
no	yes	3,400,000	40,000
yes	yes	1,800,000	40,000

Step 5 - Subtraction of costs and multiplication by frequency

The calculation in Step 4 was made with and without the gas control system present. The control system is assumed to be fully effective in preventing early failure. The difference between the cases where gas control is 'yes' and the cases where gas control is 'no,' when multiplied by the SBO frequency, represents the averted offsite cost on a per reactor-year basis.

The results are summarized for Sequoyah for accidents with and without late failure in Table 5 below. Costs are divided into offsite and onsite costs, as well as total costs. Offsite costs are the dominant contributor in all cases. Costs are in 2002 dollars.

Table 5: Sequoyah Cost Summary per reactor year				
Internal Events	SBO frequency	Total Averted Offsite Costs $k per reactor year	Averted Onsite Health Effects Costs $k per reactor year	Total Averted Costs $k per reactor year
No Late Failure	1.5E-5	28	0.053	28
with Late Failure	1.5E-5	24	0	24

Step 6 - Calculation of lifetime benefit

Multiplication by the present worth factor, based on the discount rate selected and plant lifetime remaining, yields the total averted offsite cost, or benefit, over the plant's lifetime. Results for a lifetime of 40 years for a discount rate of 7% and 3% are shown in Tables 6 and 7 respectively. This step completes the analysis.

Table 6: Lifetime benefit base case (7% discount rate)			
Internal Events	Lifetime Averted Offsite Costs 2002$k	Lifetime Averted Onsite Health Effects Costs 2002$k	Lifetime Total Costs Averted 2002$k
No Late Failure	370	0.7	370
with Late Failure	320	0.	320

Table 7: Lifetime benefit sensitivity case (3% discount rate)			
Internal Events	Lifetime Averted Offsite Costs 2002$k	Lifetime Averted Onsite Health Effects Costs 2002$k	Lifetime Total Costs Averted 2002$k
No Late Failure	650	1.2	650
with Late Failure	560	0.	560

The results are dominated by the offsite costs. Inclusion of averted onsite costs produces a negligible change in all cases. However, since the ice condenser containments are mostly dual units, the discussion of Section 3 regarding onsite costs related to the effect of containment failure of the damaged unit on the undamaged unit may apply. This means that for the case where containment failure is averted, the onsite averted costs could be significantly higher than estimated here, under certain conditions, as discussed in Section 3. However, if late containment failure occurs, the benefit from averted onsite costs is likely to be very small. This is due to the assumption that the main driver is the additional cost of site cleanup and decontamination of the undamaged unit from failure of containment of the damaged unit. This cost is assumed to be the same whether containment fails early or late, thus combustible gas control will offer very little benefit in terms of onsite costs if late failure occurs.

4.2 PWR Ice Condenser Uncertainty Considerations

When considering uncertainties in the results, uncertainties in the Level 1, Level 2, and Level 3 analyses should be accounted for.

For the issue of combustible gas control in containment this means that the uncertainties to be considered are:

1. the uncertainty in the core damage frequency (CDF) contribution from station blackout (SBO).

2. the uncertainty in the conditional probability of early containment failure (CPEF) due to gas combustion, given station blackout has occurred, and
3. the uncertainty in the releases and associated consequences.

In practice to date a number of studies have provided estimates of (1), very few have included (2) and/or (3).

To estimate the uncertainty in benefits achieved by enhancing gas control in ice condenser containments to operate under SBO conditions, BNL:

1. made additional benefit estimates based on the uncertainty results from the NUREG 1150 study for Sequoyah [4,5],
2. reviewed some PRA results recently provided by Duke Power from their PRAs of the Catawba and McGuire plants [9] and calculated benefits with the results provided in these models, and
3. ran the latest available SPAR model for Catawba and McGuire and calculated benefits based on the uncertainty in the SBO frequencies provided in these models,
4. reviewed the IPEs and IPEEEs for variation in SBO CDF and variation in CPEF for ice condensers.

NUREG-1150 Sequoyah uncertainty results

Table 1 above summarized the 5th percentile, mean and 95th percentile values for both the SBO CDF frequency and the CPEF found for Sequoyah in the NUREG-1150 study.

Unfortunately the NUREG-1150 reports do not present the integrated uncertainty from the SBO core damage frequency distribution convolved with the conditional early containment failure probability distribution. However, Figure 2.5-5 of NUREG/CR-4551, Vol.5, Rev 1, Part 1 [5] provides some insight on the range of the combined uncertainties. That figure, which presents frequency distributions of various accident progression bin (APBs) groups, indicates that the 95th percentile of the frequency (i.e., the CDF combined with conditional failure probability) of various scenarios involving early containment failure is no more than one order of magnitude larger than the mean value of the frequency. This data can be used to estimate an upper bound of the 95th percentile of the combined uncertainty by arguing, based on the Figure 2.5-5 results, that the additional uncertainty introduced by the CPEF variability will be limited to an increase of 10 times the result obtained with the CDF and CPEF mean value. This is less than a value obtained by using the 95th percentile SBO CDF and the 95th percentile CPEF to calculate benefit, which would obviously represent a more extreme value than the 95th percentile of the combined uncertainty distribution.

For a lower bound Figure 2.5-5 is not much help since the 5th percentiles of the frequency in that figure are more than 3 orders of magnitude below the mean. However, a lower bound on the benefits from the SBO distribution alone results in very low values (as shown below in Table 12), so a combined lower bound is not of interest.

The benefits for Sequoyah were also calculated using the conditional early containment failure probabilities due to hydrogen combustion events during SBO based on the results of NUREG/CR-6427 [7]. This is a recent, detailed study of severe accident phenomena in ice condenser containment plants, focused on the direct containment heating issue, carried out by Sandia National Laboratories(SNL), which assigns a very high CPEF due to hydrogen for Sequoyah.

PRA results recently provided by Duke Power

In an email communication of September 20, 2002 Duke Power provided selected results from their latest PRAs for the Catawba and McGuire plants. These results consisted of:

1. SBO CDF's for internal events (but including tornado), with point estimates, mean, median, 5th and 95th percentiles of CDF provided. (3 different cases were provided for Catawba), and point estimates of selected SBO CDF's for external events (tornado and seismic).
2. ranges of containment failure probabilities associated with the relevant SBO plant damage states used in the PRA,
3. early containment failure public health risk results, including person-rem per year, from the studies, and
4. definitions of the early failure release classes used to obtain the health effects.

The relevant core damage frequencies provided by Duke are shown in Table 8 below:

Table 8 SBO core damage frequencies (per ry)

Plant Conditional Containment Failure Probabilities	**Internal Events**				**External Events**
	Pt Est	**5th**	**mean**	**95th**	**Pt Est**
Catawba	*Duke PRA Rev 2b*				
Prob of early failure range: 0.16 to 0.21- slow SBO 0.16 to 0.34 - fast SBO	1.5E-5	9.4E-7*	1.9E-5*	6.4E-5*	1.0E-5
	Duke Rev 2b with RCP seal replaced				
Prob of late failure range: 0.72 to 0 84 - slow SBO 0 68 to 0.84 - fast SBO	9.8E-6	5.2E-7*	1.3E-5*	4.5E-5*	NA
	Duke Rev 2b w RCP seal replaced & flood wall installed				
	1.2E-6	1.5E-7*	2.6E-6*	8.7E-6*	NA
McGuire	*Duke PRA Rev 3*				
Prob of early failure range: 0.15 to 0.19- slow SBO 0.16 to 0.26 - fast SBO Prob of late failure range: 0.34 to 0.56 - slow SBO 0.17 to 0.36 - fast SBO	1.2E-6	2.2E-7*	3.0E-6*	9.9E-6*	8.9E-6

* includes SBO frequency due to tornado

With regard to item (3), it was noted that person-rem results for early failures seemed less by a factor between 3 and 4 than those found for NUREG-1150 early failures from comparable scenarios. This difference in health risk was then traced to differences between item (4) above and the release classes from NUREG-1150 for comparable scenarios. Table 9 below shows the differences between a typical release class from item (4) and a typical NUREG-1150 release.

Table 9

	Duke email Catawba	NUREG-1150 Sequoyah
Release Fractions		
Xe	1.0E+00	8.8E-01
I	5.5E-02	2.9E-01
Cs-Rb	4.8E-02	2.6E-01
Te-Sb	3.0E-02	2.1E-01
Ba	1.7E-03	6.5E-02
Ru	2.2E-03	6.0E-03
La	1.2E-04	8.0E-03
Sr	2.5E-04	6.4E-02

As can be seen from this table, the NUREG-1150 release fractions for the important radionuclides are about a factor of 4 higher than the ones used in the Duke PRA. The Duke results were obtained using the MAAP code, while the NUREG-1150 results were obtained with the Source Term Code Package and MELCOR. Apparently the differences in the release fractions in the above Table is primarily attributable to the use the different codes in the two analyses.

SPAR Model Runs

BNL ran the latest available SPAR model for the Catawba and McGuire plants, i.e., the 3i model, and calculated benefits with results from these models. These are internal events, Level 1 models which incorporate uncertainty parameters and can calculate, in addition to a point estimate, the mean, median and 5th and 95th percentiles associated with the CDF of a particular accident class, such as SBO. The SBO frequencies used in these models are listed in Table 10 below:

Table 10 SPAR 3i SBO CDF ranges for internal events (ry)

Plant	5th	mean	point estimate	95th
Catawba	6.8E-7	2.4E-5	2.8E-5	9.6E-5
McGuire	1.6E-6	2.4E-5	2.2E-5	8.5E-5

Since these are Level 1 models only, there is no information on CPEF or accident progression in the models, and the benefit analyses had to use the Sequoyah NUREG-1150 accident progression and

source terms. Therefore benefit results are directly proportional to the ratio of the SBO frequencies shown in Table 10 and those for Sequoyah shown in Table 1. As can be seen the SPAR model frequencies for Catawba and McGuire are somewhat (30% to 80%) higher than the NUREG-1150 Sequoyah sequences. The SPAR model frequencies are also significantly higher than the SBO frequencies for Catawba and McGuire in the Duke Power PRAs, discussed above.

However, these models have not undergone a quality assurance process as yet, and the model software warns the user that the 3i versions are developmental versions that have not been peer reviewed, may contain errors and may change. After receipt of the Duke Power results for the Catawba and McGuire plants, which are based on more up to date information, it was decided not to include the SPAR model benefit results for Catawba and McGuire in this report.

IPE and IPEEE Comparisons

The PRAs conducted for the Individual Plant Examination (IPE) Program and the IPE External Events (IPEEE) Program did not include uncertainty estimates. However, a survey of the SBO frequencies and containment failure probabilities used in the IPE and IPEEEs was carried out for this report and the results are shown in Table 11, including some of the reasons for the variation in frequency.

Table 11 SBO Frequencies from the IPEs (ry)

Plant	Internal Events	External Events	Additional information from IPEs
Catawba	1.5E-5	1.4E-5	SBO mainly from internal floods Without floods frequency<10E-6 Shares DG from safe shutdown facility Low probability for failure to restore off-site power
D.C. Cook	1.2E-6	5.3E-6	IPE states off-site power very reliable AFW manually controlled after battery depletion
McGuire	9.3E-6	2.3E-5	Standby shutdown facility can provide seal cooling
Sequoyah	5.3E-6	not available	Can cross-tie DC to operate turbine driven AFW
Watts Bar	1.7E-5	not available	Short term SBO is an important contributor

As Table 11 indicates, the internal events SBO CDFs for ice condenser plants in the IPEs are in the range of, or below, the Sequoyah NUREG-1150 mean SBO frequency used in the benefit calculations in this report. The external event frequencies for Catawba and McGuire in the IPEs are considerably higher than the frequencies listed in the current Duke Power PRAs for these plants, as shown in Table 8.

The total (conditional on core damage, not just on SBO) CPEFs in the IPEs for the ice condenser

plants were all surprisingly low, i.e., ~0.02 or less, and even smaller than CPEFs for large dry containments. Therefore, benefit calculations based on the IPEs for ice condenser plants would yield significantly lower dollar values than the benefits calculated with the Sequoyah NUREG-1150 numbers or the Catawba and McGuire Duke Power input.

Variation in population density around the plant sites was also surveyed. Based on FSAR projections, McGuire has the highest projected year 2000 (50 mile radius) population density, about 2.3 times that of Sequoyah, which has the lowest. The Catawba population is projected as 1.8 times that of Sequoyah, D. C. Cook's is 1.3 times, and Watts Bar's is about the same as Sequoyah.

4.3 Summary of PWR Ice Condenser Results

Table 12 summarizes the results of the calculations carried out for estimating the benefit of an enhanced combustible gas control system for the ice condenser plants. Results, in terms of averted costs in $k, are shown for 3 Sequoyah cases, 9 Catawba cases and 3 McGuire cases. The columns in the table are arranged as follows:

Column 1 provides the plant name and the case number.

Column 2 lists the containment failure probabilities used and their source.
N1150 refers to the NUREG-1150 study and the supporting documents [4,5,6].
N/C 6427 refers to the SNL report NUREG/CR-6427 [7].
Duke PRA range refers to the ranges provided in the Duke email of 9/20/02 [9].

Column 3 indicates the source used to calculate the consequences.
1150S refers to the NUREG-1150 parameters for Sequoyah, but updated to the values used in NUREG/CR-6349 [10].
Duke refers to the parameters used in the Duke PRA [9].
1150S*1.8 and 1150s*2.3 refers to the 1150S values scaled by a factor for differences in population density.

Columns 4 - 7 give averted costs in $k for internal events obtained by combining the SBO frequencies obtained from a point estimate (col 4), the 5th percentile (col 5), the mean (col 6), and the 95th percentile (col 7), each combined with the containment failure probabilities shown in column 2.

Column 8 gives the internal events averted cost estimate approximating the upper bound 95th percentile of the combined SBO CDF and CPEF uncertainty, based on the discussion of Figure 2.5-5 of NUREG/CR-4551, Vol.5, Rev 1, Part 1, provided above.

Column 9 provides the averted cost based on the external events SBO frequency, for which only point estimates exist.

The PRA source of the SBO frequencies for each plant are indicated across the columns.

Table 12 Averted Costs ($k)

Plant	Case		Source of SBO frequency used					
	Cond Cntmt Failure Prob	Source Term	Internal Events					External Events
			Pt Est	Uncertainty			Upper Bound Estimate of 95th combined (Lv1&Lv2) uncertainty	Pt Est
				5th	mean	95th		
Sequoyah			*NUREG-1150*					
1	EF =0 15 (N1150 mn)	1150S (updated)	NA	11	320	1,200	3,200	NA
2	EF =0 65 (N1150 95th)			50	1,400	5,000		
3	EF=0 97 (N/C 6427)			74	2,100	7,500		
Catawba			*Duke PRA Rev 2b*					
1	EF=0.29 LF=0 71 (N/C6427 & Duke PRA range)	Duke	180	11*	220*	750*	2,200*	120
2		1150S	640	40*	790*	2,700*		420
3		1150S*1.8	870	54*	1,100*	3,700*		580
			Duke Rev 2b with RCP seal replaced					
4	same as above	Duke	120	6*	150*	530*	1,500*	NA
5		1150S	420	22*	540*	1,900*		
6		1150S*1.8	570	31*	740*	2,600*		
			Duke Rev 2b w RCP seal replaced & flood wall installed					
7	same as above	Duke	14	2*	31*	100*	310*	NA
8		1150S	52	7*	110*	370*		
9		1150S*1.8	70	9*	150*	500*		
McGuire			*Duke PRA Rev 3*					
1	EF=0.26 LF=0 56 NF=0.18 (Duke PRA range)	Duke	13	2*	32*	110*	320*	98
2		1150S	44	8*	110*	380*		340
3		1150S*2.3	72	13*	180*	600*		540

* includes SBO frequency due to tornado

The following assumptions apply to all the cases shown in Table 12:

1. 40 year plant life remaining
2. 7% discount rate (3% discount rate would increase all results by a factor of 1.74)
3. late failure is not averted by the enhancement (thus, with the assumptions made for these analyses, on-site health costs are not relevant)

Cases:

Sequoyah 1
For all the Sequoyah cases the SBO frequencies from the NUREG-1150 studies are used, and the consequences are estimated based on the NUREG-1150 source terms, as updated in NUREG/CR-6349 [10], and updated for inflation and population increase. The first case is calculated using the mean early containment failure probability from NUREG-1150.

Sequoyah 2
Same as Sequoyah 1 but using the 95th percentile of the mean early containment failure probability from NUREG-1150.

Sequoyah 3
Same as Sequoyah 1 but using the early containment failure probability from NUREG/CR-6427.

Catawba 1
SBO frequencies are from Rev 2b of Duke's PRA for Catawba. Note that the point estimate for internal events truly is internal events only, but that the 5th, mean and 95th values include tornados. The point estimate for tornados is given separately in the PRA and is only about 10% of the mean (which includes internal events and tornados). Therefore the inclusion of the tornado events does not have a big effect. Containment failure probability values are within the range for failure probabilities used in the Duke PRA and the same as those in NUREG/CR-6427 for Catawba. The source term person-rem was extrapolated from the health risk information provided in the Duke email, with off-site costs scaled from NUREG-1150 off-site cost estimates based on the comparable person-rem ratios.

Catawba 2
Same as Catawba 1 but using the NUREG-1150 source term/consequence results (i.e., those used in Sequoyah cases above). This was done as a sensitivity based on the differences shown in Table 9 above.

Catawba 3
Same as Catawba 2, but since the population around Catawba is larger than that around Sequoyah by a factor of about 1.8, the Sequoyah person rem were increased by that factor.

Catawba 4, 5 & 6
Same as Catawba 1 ,2&3 respectively, but with the SBO frequencies taking into account RCP seal replacement. The point estimate for tornados is only about 9% of the mean, so again the inclusion of the tornado events does not have a big effect.

Catawba 7, 8 & 9
Same as Catawba 1, 2 & 3 respectively, but with the SBO frequencies taking into account RCP seal replacement and installation of a flood wall. The point estimate for tornados is about 44% of the mean. Therefore here the inclusion of the tornado events does have a large effect.

McGuire 1
SBO frequencies are from Rev 3 of Duke's PRA for McGuire. Again the point estimate for internal events is truly for internal events only, but the 5th, mean and 95th values include tornados. The point estimate for tornados is about 51% of the mean. Therefore the inclusion of the tornado events does have a large effect. Containment failure probability values are within the range for failure probabilities used in the Duke PRA. The source term person-rem was extrapolated from the health risk information provided in the Duke email, with off-site costs scaled from NUREG-1150 off-site cost estimates based on the comparable person-rem ratios.

McGuire 2
Same as McGuire 1 but using the NUREG-1150 source term/consequence results (i.e., those used in Sequoyah cases above). This was done as a sensitivity based on the differences shown in Table 2 above.

McGuire 3

Same as McGuire 2, but since the population around McGuire is larger than that around Sequoyah by a factor of about 2.3, the Sequoyah person rem were increased by that factor.

Note that uncertainties associated with issues such as spontaneous ignition burning off accumulated hydrogen, and less than 100% reliability of the gas control system, would only affect the value of CPEF avoided and therefore can be accounted for by varying CPEF. Also note that, aside from the sensitivity calculation with the two different source terms, no uncertainties in the Level 3 part of the calculations involved in the averted cost have been addressed.

It should also be pointed out that the inclusion of averted costs from external events assumes that the combustible gas control system is designed to withstand the external event. For example, the control system would have to be seismically qualified to the appropriate g level to withstand an earthquake of a certain magnitude. Obviously this would increase the cost of the combustible control system above that designed to deal only with internal events.

5. RESULTS FOR A BWR MARK III PLANT

In this Section the benefits accrued from a combustible gas control system which remains functional during SBO sequences are calculated for the Grand Gulf plant, a BWR 6 with a Mark III containment, based on the NUREG-1150 study of Grand Gulf.

The NUREG-1150 study for Grand Gulf was an integrated study (Level 1, Level 2, and Level 3) PRA study and provides, separately, uncertainty ranges for core damage frequency (Level 1) as well as containment failure probability (Level 2). However, only internal events were examined for Grand Gulf in the NUREG-1150 study. Grand Gulf core damage frequency ranges due to station blackout events are presented in Table 6.2 of NUREG-1150 Volume 1 [4]. A histogram of early containment failure probability consequential to SBO for Grand Gulf, is shown in Figure 2.5-2 of NUREG/CR-4551, Vol.6, Rev 1, Part 1 [6]. Table13 below summarizes the values in the reports.

Table 13 Grand Gulf uncertainty ranges for internal events

	5th	mean	95th
SBO CDF frequency from NUREG-1150 (ry)	1.7E-7	3.9E-6	1.1E-5
CPEF due to SBO from NUREG/CR-4551, Vol.6	~1.E-2	~0.5	~1.0

5.1 BWR Mark III Example Benefit Calculations

The benefit calculation for Grand Gulf, using mean values from NUREG-1150, is carried out below following the steps at the beginning of Section 2 of this report.

Step 1 - Frequencies of SBO sequences

As indicated in Table 13, the mean SBO core damage frequency from internal events found in the NUREG-1150 study was 3.9E-6 per reactor year.

Step 2 - Change in conditional containment failure probability

Considerable information on accident progression and hydrogen deflagration and detonation for Grand Gulf was developed during the NUREG-1150 study and is documented in NUREG-1150 and the supporting documents [4,6]. This information is summarized in Reference 8 and the following discussion is based on Reference 8.

Mark III containments depend on glow plug hydrogen igniters to control pressure loads resulting

from hydrogen combustion events. If the igniters are not operating, due to lack of AC power (the dominant sequence being a station blackout) or operator failure to manually actuate them, there is a possibility of an energetic hydrogen combustion (deflagration or detonation) event at the time of vessel failure (or at other times if the operators fail to follow procedures and the igniters are actuated when a significant amount of hydrogen has accumulated). These energetic combustion events were stated in NUREG/CR-1150 and the supporting documentation for Grand Gulf (NUREG/CR-4551, Volume 6 [6]) to result in early containment failure with a relatively high conditional probability (~0.5). However, in a Mark III containment an unscrubbed release (one which does not pass through the suppression pool) requires failure of the drywell in addition to containment failure. Drywell failure can occur: (1) directly as a result of loads associated with vessel breach or from hydrogen combustion, or (2) indirectly as a result of structural failure of the pedestal.

Before vessel breach the only significant event that was found in NUREG/CR-4551, Volume 6, to cause drywell failure was hydrogen combustion in the wetwell. However, at the time of vessel breach loads from direct containment heating, ex-vessel steam explosions, hydrogen combustion, and RPV blow down contribute to the probability of drywell failure. Accordingly, loads from high pressure vessel breach and hydrogen combustion were determined to be the leading causes of containment and drywell failure.

The Grand Gulf (NUREG/CR-4551, Volume 6) results are summarized in the Table 14 below. This Table indicates that accident sequences that contribute to large releases (which require failure of the drywell in addition to containment failure) are sensitive to the type of accident (i.e., SBO vs non-SBO) and the pressure (i.e., transient vs large break LOCA) in the reactor pressure vessel at the time of vessel breach.

Table 14:
Conditional Containment and Drywell Failure Probabilities for Mark III Containments

RCS Pressure at Vessel Breach	Station Blackout, SBO (Igniters and Sprays unavailable)		Non-SBO (Igniters and Sprays available)	
	Containment Fail	Containment and Drywell Fail	Containment Fail	Containment and Drywell Fail
High	~ 0.5	~ 0.2	~ 0.5	~ 0.2
Low	~ 0.5	~ 0.2	~ 0.01 - 0.02	~ 0.01

As shown in the Table, if the RCS is at high pressure the likelihood of containment failure is relatively independent of whether or not the igniters are operating. In addition, the likelihood of simultaneous failure of the drywell is also independent of igniter operation if the RCS is at high pressure.

As the above Table indicates, if the RCS is depressurized at vessel breach the likelihood of

containment failure is dependent on whether or not the igniters are operating. If the igniters are not available the conditional probability of containment failure is approximately 0.5 even with the RCS at low pressure. The likelihood of simultaneous failure of the drywell is also about 0.2 at the time of vessel breach. Thus all SBO sequences (without combustible gas control) have a conditional probability of 0.2 of a large release, regardless of the pressure in the RCS.

The potential for containment failure at the time of vessel breach when the RCS is at low pressure and the igniters are operating is not directly assessed in NUREG/CR-4551, Volume 6. However, the conditions prior to vessel breach should be applicable to this situation because the RCS is depressurized and none of the issues associated with high pressure melt ejection would occur. The results prior to vessel breach indicate a conditional probability of containment failure in the range of 0.01 to 0.02 if the igniters are operating.

In summary, for transient sequences with the RCS at high pressure and for all SBO sequences the conditional probability is close to 0.2 that the Mark III containment fails at the same time that the suppression pool is bypassed. However, if the RCS is depressurized and the igniters are operating then the conditional probability is less than 0.1 that the Mark III containment will fail. The IPE database (www.nrc.gov/NRC/NUREGs/SR1603/index.html) information on the plant damage states (PDSs) for the four domestic Mark III plants was searched to determine the fraction of PDSs that have low RCS pressure. The average across the four plants for PDSs with this attribute is approximately 40 percent, with high RCS pressure making up the remaining 60 percent.

Based on Table 14, and the above discussion, the following event tree can be constructed and quantified, conditional on an SBO event without a hydrogen control system operating. The late failure split fractions are based on NUREG-4551 Vol. 6 results.

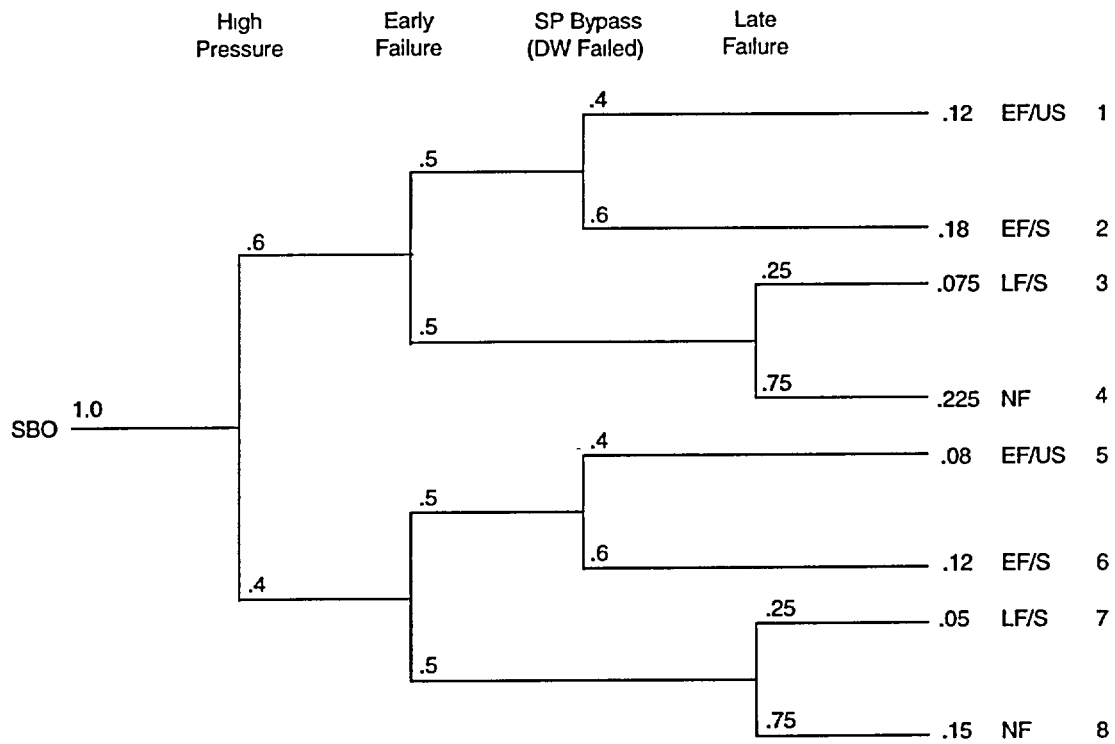

Figure 1: Containment event tree conditional on SBO without combustible gas control

The top events are high RCS pressure, early containment failure, drywell failure, and late containment failure. A late containment failure will always be scrubbed. The conditional probability for each of the 8 end states is shown in the Figure. EF, LF, and NF indicate early containment failure, late containment failure, and no containment failure, respectively. US indicates an unscrubbed release, S indicates a scrubbed release.

A similar event tree, based on Table 14 and the accompanying discussion, can be constructed for SBO events assuming combustible gas control is still functional. This event tree is shown in Figure 2. (Note that the 1.0/0.0 split fraction on the low pressure branch SP Bypass event is chosen for conservatism, and has very little effect on the results).

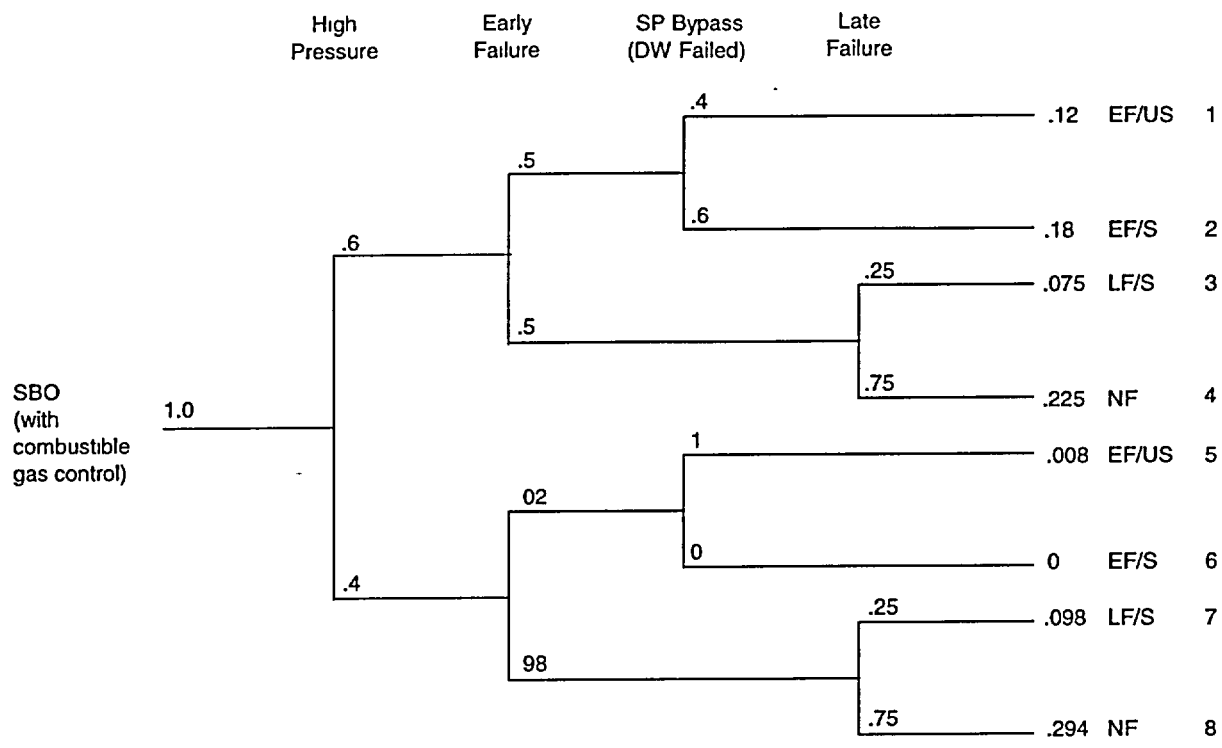

Figure 2: Containment event tree conditional on SBO with combustible gas control functional

A comparison of the trees shows that the high pressure, i.e., upper, half of both trees is identical. This means that any benefit gained from a combustible gas control system which functions during station blackout will depend only on the different conditional probabilities associated with low pressure scenarios (end states 5 through 8).

Step 3 - Consequences associated with each containment failure mode

Offsite consequences for releases at Grand Gulf representative of each of the end states indicated in Figures 1 and 2 are shown in Table 15. No consequences are assumed for no containment failure. Offsite person-rem and offsite property cost estimates are based on the data provided in References 10. These results are conditional consequences (i.e., conditional on occurrence of the release) out to 50 miles from the plant and include offsite population dose (person-rem) and offsite damage costs.

Two values for offsite person-rem are shown here as well. The 1990 values are based on Reference 10. The 2000 values have been updated based on the change in population density from 1990 to 2000 as estimated in the Grand Gulf Final Safety Analysis Report. The change is an increase of about 7%.

Two values are also shown for the offsite property damage costs. The first is taken from Reference 10 and is in 1990 dollars. The second updates the 1990 dollar values to current year dollars based

on the price inflation calculator (approximately 36% over the 1990-2002 period) of the U.S. Bureau of Labor Statistics (www.bls.gov).

Table 15: Offsite Consequences (50-mile radius) of Containment Failure Releases at Grand Gulf

Sequence	Fail Mode	Offsite Person-rem 1990	Offsite Person-rem 2000	Offsite Health Effects $k	Offsite Property 1990$k	Offsite Property 2002$k
GG-11-1	Early unscrubbed	5.7E+05	6.1E+05	1,200,000	810,000	1,100,000
GG-04-1	Early scrubbed	1.0E+05	1.1E+05	220,000	43,000	59,000
GG-18-1	Late scrubbed	7.0E+04	7.5E+04	150,000	11,000	14,000

GG-11-1 from Reference 6 is a typical early failure unscrubbed sequence with about 99% of noble gases, 38% of iodine, 14% of cesium, and 9% of tellurium released. GG-04-1 is a typical early failure scrubbed sequence with about 76% of noble gases, 5% of iodine, >1% of cesium, and negligible amounts of tellurium released. GG-18-1 is a typical late failure scrubbed sequence with about 83% of noble gases, 1% of iodine, and negligible amounts of cesium and tellurium released.

Again, it should be noted that the (1990) consequences reported in Reference 10 differ somewhat from those reported in the NUREG-1150 reports, even though Reference 10 is based on the NUREG-1150 analyses. This is primarily because in the NUREG-1150 study the consequence analysis was carried out using Version 1.5.11 of the MACCS code, while the consequences in Reference 10 were recalculated with Version 1.5.11.1 of MACCS. This later version explicitly incorporates the higher BEIR V risk coefficient for the latent cancer-dose relationship while the earlier version of MACCS used the BEIR III risk coefficient. In addition, a few input errors in the NUREG-1150 MACCS calculations were corrected for the recalculations of Reference 10.

Onsite health consequences again are calculated assuming 20,000 person-rem occupational exposure, or $40,000k after using the $2000/person-rem factor, for all early and late containment failures, and 8,000 person-rem, or $16,000k, for no containment failure. Onsite property damage is not included as per the discussion in Section 3.

Step 4 - Summation of conditional containment failure modes and their consequences

The results of the summation of conditional containment failure modes and their consequences are shown in Table 16.

Table 16: Summation of Offsite Costs and Onsite Health Effect Costs		
Gas Control	Total Offsite Cost conditional on SBO ($k)	On-site Health Effects Cost conditional on SBO ($k)
no	570,000	31,000
yes	380,000	28,000

Step 5 - Subtraction of costs and multiplication by frequency

The calculation in Step 4 was made with and without the gas control system present. The difference between the cases where gas control is 'yes' and the cases where gas control is 'no,' when multiplied by the SBO frequency, represents the averted offsite cost on a per reactor-year basis. The results are summarized for Grand Gulf in Table 17 below. Costs are divided into offsite and onsite costs, as well as total costs. Offsite costs are the dominant contributor in all cases. Costs are in 2002 dollars.

Table 17: Cost Summary per reactor year for Grand Gulf (Internal Events)			
SBO frequency	Total Averted Offsite Costs $k per reactor year	Averted Onsite Health Effects Costs $k per reactor year	Total Costs $k per reactor year
3.9E-6	0.76	.014	0.77

Step 6 - Calculation of lifetime benefit

Multiplication by the present worth factor, based on the discount rate selected and plant lifetime remaining, yields the total averted offsite cost, or benefit, over the plant's lifetime. Results for a lifetime of 40 years for a discount rate of 7% and 3% are shown in Tables 18 and 19 respectively. This step completes the analysis.

Table 18: Lifetime benefit base case (7% discount rate) for Grand Gulf			
Internal Events	Lifetime Averted Offsite Costs 2002$k	Lifetime Averted Onsite Health Effects Costs 2002$k	Lifetime Total Costs Averted 2002$k
	10k	0.18	10k

Table 19: Lifetime benefit sensitivity case (3% discount rate) for Grand Gulf			
Internal Events	Lifetime Averted Offsite Costs 2002$k	Lifetime Averted Onsite Health Effects Costs 2002$k	Lifetime Total Costs Averted 2002$k
	18	0.3	18

The results are again dominated by the offsite costs but are much smaller than for the ice condensers. For Grand Gulf the total averted offsite costs due to internal events amount to $10k for a 7% discount rate and $18k for a 3% discount rate.

Inclusion of averted onsite costs produces a negligible change in all cases. Since the Mark III containments considered here are single nuclear units, the discussion of Section 3 regarding onsite costs related to the effect of containment failure would imply that onsite property damage costs averted by adding a combustible gas control system which functions under SBO conditions would also be small.

5.2 BWR Mark III Uncertainty Considerations

To estimate the uncertainty in benefits achieved by enhancing gas control in BWR Mark III containments to operate under SBO conditions, BNL:

1. made additional benefit estimates based on the uncertainty results from the NUREG 1150 study for Grand Gulf, and
2. ran the latest available SPAR model for Grand Gulf and River Bend and calculated benefits based on the uncertainty in the SBO frequencies provided in these models.
3. reviewed the IPEs and IPEEEs for variation in SBO CDF and variation in CPEF for Mark III plants.

No recent industry PRAs, similar to those made available for the ice condenser plants, were available for the Mark III benefit estimates.

NUREG-1150 Grand Gulf

Table 13 above summarized the 5th percentile, mean, and 95th percentile values for both SBO CDF and the CPEF found for Grand Gulf in the NUREG-1150 study.

A series of benefit calculations was made using the NUREG-1150 SBO frequencies and the accident progression scenarios from Figures 1 and 2, above. The results of the calculations are summarized in Table 22 below. Benefits were estimated with the split fractions in Figures 1 and 2 (which assume the NUREG-1150 mean value for CPEF) for the 5th, mean and 95th percentile NUREG-1150 SBO frequencies (Grand Gulf 1 in Table 22).

To further examine the uncertainty in benefits, a sensitivity calculation was made using the 95th percentile for CPEF, which is essentially 1.0, i.e., the containment fails always (Grand Gulf 2 in Table 22). This assumption will increase the benefit from gas control during SBO.

Another sensitivity calculation was made to further increase the benefits by assuming half (rather than 40%) of all sequences are at low pressure, and assuming drywell failure occurs whenever containment fails (Grand Gulf 3 in Table 22). This is quite a conservative case and should provide some reasonable upper bound on the benefit.

Since benefits are already low in the base case, no lower range sensitivity calculation was carried out.

SPAR Model Runs

To further estimate benefits as well as the uncertainty associated with the Level 1 PRA calculations, BNL ran the latest available 3i SPAR model for Grand Gulf, an internal events, Level 1 model, which incorporates uncertainty parameters and can calculate a point estimate, the mean, median and various percentiles associated with the SBO CDF. The model incorporates up to date information on loss of off-site power frequency and emergency diesel generator availability. Similar to the ice condenser models, these Mark III SPAR models have not undergone a quality assurance process as yet, and the model software warns the user that the 3i versions are developmental versions that have not been peer reviewed, may contain errors and may change. However, since no up to date Mark III PRAs were made available for the benefit estimates, the results with the SPAR model frequencies are included here. The NUREG-1150 accident progression was again assumed, and the same sensitivity cases were run. The results are illustrated in Table 22 (Grand Gulf 4, 5, 6).

In addition, the 3i SPAR model for River Bend was also exercised and benefit results were obtained, again using the NUREG-1150 Grand Gulf accident progression scenario for the Level 2 analysis. For the consequence calculations, the NUREG-1150 Grand Gulf person-rem values for all sequences were increased by a factor of 3.1 to account for the increased population density around River Bend. Benefits were again calculated for the base case of the accident progression split fractions of Figures 1 and 2 and the two sensitivity cases (River Bend 1, 2, 3, respectively in Table 22). SPAR model SBO frequencies are shown in Table 20.

Table 20 SPAR 3i SBO CDF ranges for internal events (ry)

	5th	mean	95th
Grand Gulf	1.4E-7	2.4E-6	8.2E-6
River Bend	2.7E-8	1.0E-5	2.8E-5

The uncertainty associated with the Level 2 calculations for Grand Gulf cannot be estimated with the SPAR models, since no Level 2 SPAR models incorporating uncertainty are available.

IPE and IPEEE Comparisons

The PRAs conducted for the Individual Plant Examination (IPE) Program and the IPE External Events (IPEEE) Program did not include uncertainty estimates. However, a survey of the SBO frequencies and containment failure probabilities used in the IPE and IPEEEs was carried out for this report and the results are shown in Table 21, including some of the reasons for the variation in frequency.

Table 21 SBO Frequencies from the IPEs (ry)

Plant	Internal Events	External Events	Additional information from IPEs
Clinton	9.8E-6	not available	Separate SSW system for emergency loads For LOSP uses high initiating event and non-recovery frequency
Grand Gulf	7.5E-6	not available	Separate SSW system for emergency loads SSW pump room ventilation failure an important contributor
Perry	2.2E-6	not available	Only Mark III to credit fire water for injection early in SBO sequences
River Bend	1.4E-6	not available	SSW failures lead to short term SBO Credits prevention of switchover to high temp suppression pool to keep RCIC working

As Table 21 indicates, the internal events SBO CDFs for Mark III plants in the IPEs are well within the range (5th to 95th percentile) of the Grand Gulf NUREG-1150 SBO frequency and the SPAR model frequencies. Note that the River Bend IPE frequency is an order of magnitude lower than the 3i SPAR model frequency. No external event frequencies are available for Mark III plants from the IPEEEs.

Variation in population density around the plant sites was also surveyed. Based on FSAR projections, Perry has the highest projected year 2000 (50 mile radius) population density, about 7.5 times that of Grand Gulf, which has the lowest. Both Clinton and River Bend have population densities that are about 3.1 times that of Grand Gulf.

Although Perry has the highest population ratio, it also has the lowest SBO frequency. Therefore, since the estimates for River Bend were done with the (high) SPAR 3i model SBO frequencies and by accounting for the increased population density around River Bend (vs. Grand Gulf), the River Bend calculations (River Bend 1, 2, 3, in Table 22) should provide a bound for all four Mark III sites.

5.3 Summary of BWR Mark III Results

Table 22 summarizes the results of the calculations carried out for estimating the benefit of an enhanced combustible gas control system for the BWR Mark III plants. Note that no uncertainties in the Level 3 part of the calculations involved in the averted cost have been addressed.

Table 22 Averted Costs ($k)

Plant & Case description		Source of SBO frequency			
		Internal Events			External Events
		5th	mean	95th	
Grand Gulf		*NUREG-1150*			
1	Mean NUREG-1150 CPEF Split fractions from Figs 1&2	<1	10	29	NA
2	95th NUREG-1150 CPEF Split fractions from Figs 1&2	<1	22	61	
3	95th NUREG-1150 CPEF 50% of sequences at low pressure, drywell always fails if containment fails	2	60	170	
		SPAR 3i			
4	Mean NUREG-1150 CPEF Split fractions from Figs 1&2	<1	6	22	NA
5	95th NUREG-1150 CPEF Split fractions from Figs 1&2	<1	13	45	
6	95th NUREG-1150 CPEF 50% of sequences at low pressure, drywell always fails if containment fails	2	36	120	
River Bend		*SPAR 3i*			
1	Mean NUREG-1150 CPEF Split fractions from Figs 1&2	<1	57	160	NA
2	95th NUREG-1150 CPEF Split fractions from Figs 1&2	<1	120	330	
3	95th NUREG-1150 CPEF 50% of sequences at low pressure, drywell always fails if containment fails	<1	320	880	

The following assumptions apply to all the cases shown in Table 22:

1. 40 year plant life remaining
2. 7% discount rate (3% discount rate would increase all results by a factor of 1.74)

6. DISCUSSION OF RESULTS

Comparison of the results in Section 4 for the PWR ice condenser plants with the results in Section 5 for the BWR Mark III plants shows that the estimated benefit of providing combustible gas control during SBO sequences differs significantly for these two plant types. Using lifetime averted offsite costs for internal events for the example case, i.e. the mean NUREG-1150 case, (7% discount rate), the Sequoyah (ice condenser) cost estimate (with late failure) is $320k, while the Grand Gulf (Mark III) lifetime averted costs for the mean NUREG-1150 case is estimated at $10k. In other words, the Sequoyah results are higher than the Grand Gulf results by a factor of roughly 30.

The reasons for this large difference can be attributed to a number of factors involved in the analyses of these plants.

1. The SBO frequency is lower for Grand Gulf
2. The CPEF averted by the combustible gas control system is lower for Grand Gulf (and Mark III's in general) because
   (a) the early failure of both the containment and the drywell are necessary to obtain significant consequences, and
   (b) the igniters are assumed effective only for low pressure sequences.
3. The conditional off-site person-rem are lower for Grand Gulf.

Comparison of these parameters is illustrated in Table 24 below.

Table 24: Parameter comparison

Parameter	Sequoyah value	Grand Gulf value	Sequoyah/Grand Gulf
SBO frequency	1.5E-5	3.9E-6	3.8
Approximate averted CPEF*	0.15	0.09	1.7
Off-site person rem 2000 estimate	3.1E+6	6.1E+5	5.1
TOTAL FACTOR			~30

*CPEF: for Grand Gulf the value shown is a weighted (by consequences) average of the CPEF averted in end states 5 and 6 of Figure 2.

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Backup Power for PWRs with Ice Condenser Containments and for BWRs with Mark III Containments under SBO Conditions: Impact Assessment

Revision 2

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Executive Summary

In support of resolution of Generic Safety Issue 189 (GSI-189), a cost (impact) assessment for providing backup power to hydrogen igniters for PWRs with ice condenser (IC) containments and for BWRs with Mark III containments under station blackout (SBO) conditions has been performed. The methodology used is consistent with the Value-Impact (cost-benefit) portions of a regulatory analysis as defined and described in NUREG/BR-0058, Rev. 3 and NUREG/BR-0184.

Under SBO conditions, these containment types are vulnerable to failures from hydrogen deflagrations, failures what would otherwise be prevented if the existing hydrogen igniter systems were energized.

The costs for implementing and maintaining backup power for these systems for the life of the plants are estimated by considering three cases: 1) a pre-staged diesel generator powering only the hydrogen igniters (base case), 2) a portable diesel generator powering only the hydrogen igniters, and 3) a pre-staged diesel generator powering both hydrogen igniters and air return fans for ice condenser plants. For each candidate regulatory action, estimates are made for implementation and operational (recurring) costs for both the licensee and the NRC. Licensee implementation costs included allowance for materials and equipment, installation, engineering, worker dose, emergency procedures, and licensing costs. Licensee operational costs considered routine periodic surveillance, maintenance and testing of the independent power supply. For the NRC, implementation costs covered rulemaking and reviews of licensee documentation, and operational costs allowed for periodic inspection.

In addition, uncertainties associated with these three cases and sensitivity cases reflecting various requirement and procedural options are assessed. The base case is a fixed, permanent installation that is energized locally and manually. The portable diesel must be transported from its storage area to a dedicated panel and manually hooked up with proper sequencing for powering the igniters.

Because of power requirements and dual-unit versus single-unit differences among the 13 reactors potentially affected by this issue, no "generic" plant would be representative. Instead, the study considered four classes of plants, namely (1) the 3 dual-unit PWR stations at McGuire, Catawba, and D.C. Cook; (2) the dual-unit PWR Sequoyah station, (3) the single-unit PWR Watts Bar plant, and (4) the four Mark III BWR plants.

The "best estimate" total cost results for the base case (pre-staged) range from about $265,000 to $320,000 per reactor for the different classes of plants. Similar estimates for Case 2 approximate $195,000 to $240,000 per reactor, and for Case 3, $570,000 to $670,000 per reactor.

An uncertainty assessment was performed for the above cases using the Monte Carlo simulation software, @RISK. This assessment was based on adopting high, most likely, and low estimates for each of the cost elements underlying the total cost estimate. High, most likely, and low values were based on industry input and engineering judgement. Using Monte Carlo sampling, @Risk propagates uncertainties in the cost elements to a probability distribution of the total cost. Estimates at the 5th percentile and 95th percentile confidence levels indicate that the uncertainties are skewed toward the higher costs.

An important consideration in the assessment of backup power options is the functional reliability of the options and the relationship between this reliability and the associated costs. System costs tend to increase as the system's reliability increases.

Since the values (benefits) of backup power are calculated assuming a perfect backup system, the benefits would need to be multiplied by the functional reliability of the backup system to obtain a realistic value for the benefits. If the functional reliability of an option is greater than 0.9, then the benefits would be reduced by, at most, ten percent. This would have a negligible effect on the overall value-impact assessment in light of the other large uncertainties.

A recent independent study at San Onofre Nuclear Generating Station, "A PRA-Based Design Change at SONGs Units 2 & 3: Add Portable Gasoline-Powered Generators for Risk Reduction," addresses similar "reliability" issues and estimated functional reliability values in the range of 97 to 98%. Since a portable generator system would probably have a lower functional reliability than a pre-staged generator system, and since a portable system can have high reliability, meaningful differences in the reliability between these systems is unlikely. Thus, for the purposes of this assessment, it is concluded that a backup system (either portable or pre-staged) can be designed which has sufficiently high functional reliability to not make it a factor in the cost-benefit assessment.

In addition to the uncertainty assessment, four sensitivity studies were performed. Three of the studies (rulemaking separate from the current 10 CFR 50.44 rulemaking; implementation requiring extended outage; and 3% real discount rate compared to standard 7%) were determined to have little impact on the costs.

The fourth study, which considered qualifying the backup power equipment for external events, does have a major cost impact. However, since the external event contributors and magnitudes vary from site to site and much of the external event information is qualitative, no detailed cost assessment was performed. Based on past experience, it is estimated that costs would double to accommodate seismic events This additional cost, of course, would vary from site to site depending on the external risk profile and on what external event accommodation would best maximize the benefits versus the costs.

In conclusion, the "best estimate" costs vary from about $195,000 to $670,000 depending on the nature of the modifications and plant-specific variabilities and expands to approximately $185,000 to $830,000 when accounting for uncertainties.

In addition to addressing the powering of hydrogen igniters under SBO conditions, the study also considered the costs of a hydrogen control capability completely independent of igniter systems, namely passive autocatalytic recombiners. The cost of these recombiners would be considerably higher than the igniter power alternatives assessed in this study.

Backup Power for PWRs with Ice Condenser Containments and for BWRs with Mark III Containments under SBO Conditions: Impact Assessment

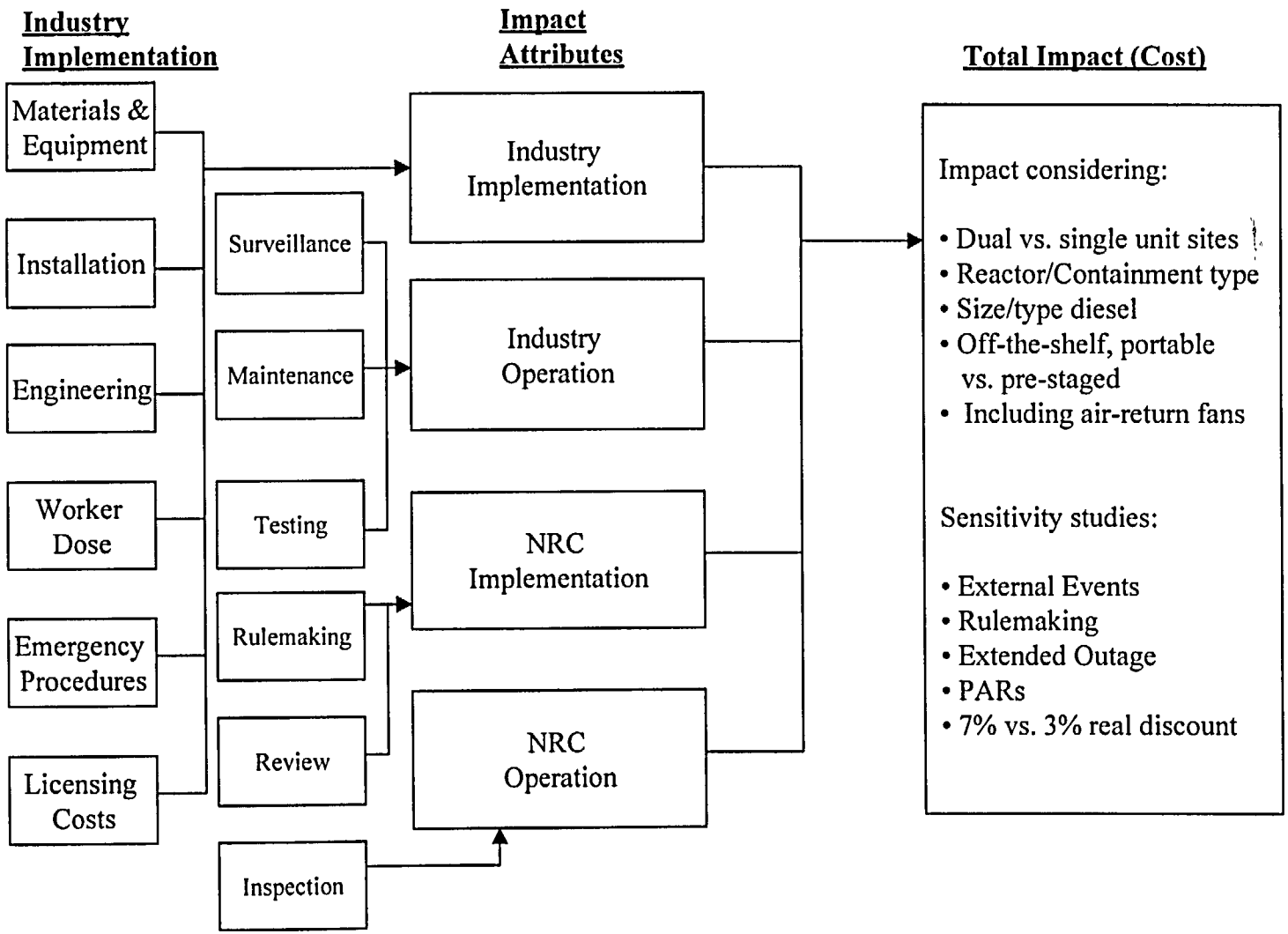
1. Introduction

The costs analyzed here together with the benefits (averted risks) analyzed in a separate document provide the data for a cost-benefit or Value-Impact assessment that can, in turn, be used as part of a regulatory analysis that assesses the pros and cons of a candidate regulatory action, including application of backfit requirements. These costs are developed consistent with the guidelines described in the Regulatory Analysis documents NUREG/BR-0058, Rev. 3 [Reference 1] and NUREG/BR-0184 [Reference 2]. They cover the full spectrum of industry and NRC costs from implementation to maintenance and inspection over the life of the plant. For each candidate regulatory action, estimates are made for implementation and operational (recurring) costs for both the licensee and the NRC. Licensee implementation costs included allowance for materials and equipment, installation, engineering, worker dose, emergency procedures, and licensing costs. Licensee operational costs considered routine periodic surveillance, maintenance and testing of the independent power supply. For the NRC, implementation costs covered rulemaking and reviews of licensee documentation, and operational costs allowed for periodic inspection. The elements of this cost (or "Impact") assessment are displayed in Figure 1-1. The cost assessment in this study follows the structure displayed in this figure and analyzes the options and sensitivities listed. The costs for a given case or sensitivity are normalized to 2002 dollars and summed to give a dollar value to the candidate regulatory action. This cost is then compared to the 2002 dollar equivalent of the benefit (or Value) from averting the risk otherwise imposed on the public from containment failure. (Note that here, the term "Cost Benefit" is analogous to the term "Value-Impact.")

The staff considered a range of potential modifications to address GSI-189 safety concerns. These included reliance on: (1) a pre-staged diesel generator to power the hydrogen igniters; (2) an "off-the-shelf" portable diesel generator to power the hydrogen igniters; (3) and a pre-staged diesel generator to power the hydrogen igniters and air return fans (ARF).

This cost analysis includes an uncertainty assessment, using the software @RISK, a Monte Carlo computer code. This assessment was based on adopting high, most likely, and low estimates for each of the cost elements underlying the total cost estimate. High, most likely, and low values were based on industry input and engineering judgement. (Note that in this report, the term "most likely" is equivalent to the term "best estimate.") Using Monte Carlo sampling, @Risk propagates uncertainties in the cost elements to a probability distribution of the total cost. Another important methodology consideration is how to "adjust," if necessary, the averted risks (benefits), which are developed under the assumption that the candidate regulatory action is 100% effective, to reflect the actual reliability of the system under study. The systems that are considered as candidates in this cost study are judged to have a "functional reliability" [1 - (hardware unreliability + hardware unavailability + human unreliability)] that is sufficiently close to 1 such that it is not an important consideration in the estimation of benefits either in an absolute or comparative sense. This aspect is also assessed in the study.

Figure 1-1 Impact (Cost) Assessment Process: GSI-189



Since, for some of the 13 units, external events are relatively important contributors to core damage from station blackout (SBO), it is important to assess the cost implications of qualifying systems for external events. For example, there will be additional costs for seismically qualifying a pre-staged diesel generator. This added cost will only be worthwhile if the added (averted risk) benefits exceed the added costs associated with seismic qualification. This is a highly complex determination. Not only do the external event contributors and associated magnitudes vary from site to site, but much of the external event information is qualitative (e.g., through the use of the seismic margins approach for evaluating seismic events) and is not conducive to estimating costs for equipment to accommodate the external events. Thus, only a general guideline on the added costs for accommodating external events is provided.

2. Objective and Scope

The objective is to support RES/DSARE in the development of a cost (impact) analysis in order to determine whether the candidate safety modifications being considered under GSI-189 are cost justified.

Costs (Impacts) are determined for the following cases.

1. Costs for a pre-staged diesel generator as backup power to the hydrogen igniters for ice condenser (IC) and Mark III plants under SBO conditions: Base Case

2. Costs for off-the-shelf portable diesel generator as backup power to the hydrogen igniters for ice condenser and Mark III plants under SBO conditions: Low Cost Case

3. Costs for pre-staged diesel generator backup power to the hydrogen igniters and air return fans (ARF) for ice condenser plants under SBO conditions

4. Costs for passive autocatalytic recombiners (PARs) for ice condenser plants and Mark III plants under SBO conditions

For these four cases, costs (impacts) are estimated for the following four attributes:

- Industry Implementation
- Industry Operation
- NRC Implementation
- NRC Operation

In addition, an uncertainty assessment is performed and other sensitivity studies are addressed, as noted below.

Except where noted, the guidance described in the Regulatory Analysis documents, NUREG/BR-0058, Rev. 3 and NUREG/BR-0184 (1997), will be used.

The following assumptions apply to all 4 cases:

- All costs are expressed in 2002 dollars.
- The remaining life of the average plant is assumed to be 40 years. This value was determined by adding 20 years (term of license renewal) to typically 20 years remaining on the plant's current license.

- For the "Operation" costs (impacts), a 7% real discount rate is used, as recommended in NUREG/BR-0184. (For the assumed 40-year remaining life of the plant, this translates into a multiplier for the year 2002 annual rate for operation costs of about 13.)
- Outage replacement power costs are zero (when considering "Industry Implementation") since it is assumed that installation of these backup power supplies can be accomplished while on-line and/or during normal outage time. A sensitivity study will consider the cost (impact) of extended outage costs.
- Rulemaking costs will be considered as minimal. This would be appropriate if the GSI-189 effort is subsumed by the current 10 CFR 50.44 rulemaking rebaselining effort. A sensitivity study will be included that assumes a major rulemaking effort.
- Costs will be determined on a "per unit" basis, with consideration of reduced per-unit costs for sites with dual units.
- It is assumed that any rulemaking associated with the resolution of GSI-189 will not affect the Station Blackout Rule or the License Renewal Rule.
- Consistent with the purpose of these options, namely to mitigate the consequences of severe accidents, the focus of equipment qualification will be the survivability of equipment, in contrast to meeting stringent design-basis requirements.
- This assessment assumes that only one backup power source will be needed during the remaining life of the plant.

Certain other assumptions are relevant only to Cases 1, 2, and 3:

- The backup power supplies will not be external event qualified. External event qualification costs will be considered as a variation of the Base Case (Sensitivity Study 1).
- One train of igniters is considered necessary and sufficient for accommodating hydrogen burns and preventing containment failure. Only train A will be powered.
- For Case 3, one air return fan is considered sufficient. Only the train A ARF will be powered.
- The hardware (e.g., backup power generators) will meet the Category 3 standards and requirements of Regulatory Guide 1.97, Revision 3 [Reference 3], unless, for certain components, a higher category will be required. Category 3 hardware needs to meet basic engineering standards but does not have to meet many of the requirements and standards associated with safety-grade systems, for example, the hardware does not have to be seismically qualified, nor does it have to meet any redundancy standards. It is assumed that all the systems that are considered as candidates in this cost study should have a "functional reliability" [1 - (hardware unreliability + hardware unavailability + human unreliability)] that is sufficiently close to 1 such that it is not an important consideration in the cost benefit analysis. If the functional reliability of an option is greater than 0.9, then the benefits would be reduced by, at most, 10%. This would have a negligible effect on the overall cost-benefit assessment in light of the other large uncertainties. A recent independent study at SONGS, "A PRA-Based Design Change at SONGS Units 2 & 3: Add Portable Gasoline-Powered Generators for Risk Reduction" [Reference 4], addresses similar "reliability" issues and estimated functional reliability values in the range of 97 to 98%. Thus, for the purposes of this study, it is concluded that a backup system can be designed which has sufficiently high functional reliability to not make it a factor in the cost-benefit assessment.

3. Estimation and Evaluation of Impacts for the GSI-189 Action

3.1 Case 1 – Costs for Backup Power to the Hydrogen Igniters for Ice Condenser and Mark III Plants During SBO Conditions: Base Case

The Base Case (Case 1) is a modest but permanent modification that can provide alternate backup power to igniters under SBO conditions. For the resolution of GSI-189, the Base Case modification will include a pre-staged diesel generator (DG) sized to power one train of igniters. Due to ventilation, radiation and fire protection concerns as well as space limitations in the auxiliary building, it is more reasonable to locate the DG outside, in an area that can be accessed by an operator. Because the alternate power supply is assumed not to be safety-related nor qualified for external events, the DG will not be housed in a separate structure. However, it is assumed that it will be designed for normal outdoor conditions, i.e., will be protected by a weather enclosure. Since the DG will be pre-staged, the cost of the modification includes installation on a concrete slab. The powering of a train of igniters from the backup power supply is assumed to be remote and local, that is, not powered from the control room. During a SBO, an operator, following appropriate procedures, would start the DG, isolate the hydrogen igniters from the existing Class 1E system, and provide power to the igniters.

For the four dual-unit IC plants, the previous assessment assumed that one pre-staged DG, centrally located between the two units, could provide backup power to the unit experiencing a SBO event. Re-analysis has shown that it would be more cost-effective to have two pre-staged DGs, one for each unit. These DGs would be located as close as practical to their respective units, close to the auxiliary building where the motor control centers that distribute normal power to the hydrogen igniters are located. The main reason why one DG would be less cost-effective is that this diesel would have to be centrally located between the two units, thereby requiring a larger amount of cable. Cable installation costs are sufficiently large to make this single diesel option more costly. This position is supported by recent comments from Duke regarding the Catawba and McGuire stations [Reference 5]. Further supporting the use of two DGs in the cost analysis are the implications of the cross-tie capability at the Sequoyah site. At sites like Sequoyah, the cross-tie capability allows for equipment from the SBO-affected unit to be powered by the existing Class 1E DG from the non SBO-affected unit. Therefore, one would expect either no SBO core damage at the site or a SBO core damage event at both units. Thus, both units would need backup power at the same time, making the use of two alternate DGs more plausible.

The existing power supply to the hydrogen igniters is Class 1E, and typically rated at 120 V. The exact tie-in to the existing power supply would be plant-specific, but for this case it is assumed to occur at a juncture just prior to the hydrogen igniters.

The table below provides the total number of igniters per unit and the total power needed for one train of igniters.

Table 3-1 Igniter Data

Plant	Total Number of Igniters per unit	Number of Igniters per Train	Power Needed for One Train of Igniters
Catawba 1 and 2	70	35	4,400 watts[1]
McGuire 1 and 2	70	35	4,400 watts[1]
D.C. Cook 1 and 2	70	35	4,400 watts[1]
Sequoyah 1 and 2	68	34	20,400 watts[2]
Watts Bar 1	68	34	20,400 watts[2]
Grand Gulf	90	45	6,000 watts[3]
River Bend	104	52	6,500 watts[1]
Clinton	115	58	7,300 watts[1]
Perry	102	51	6,400 watts[1]

[1]Assumes wattage of igniter is 125 watts
[2]Each igniter requires approximately 600 watts
[3]Grand Gulf UFSAR states one train of igniters requires 6,000 watts

Industry Implementation

This attribute accounts for the projected incremental cost on the affected licensees to install or implement mandated changes. Cost elements such as engineering, materials and equipment, structures, installation, occupational exposure, procedures and training are considered. Other costs elements such as planning, scheduling, and procurement are included with the engineering costs.

Based on the information obtained from the Individual Plant Examinations (IPEs) and updated final safety analysis reports (UFSARs), the approximate size of the generator needed to power one train of igniters ranges from 4.3 to 20.4 kW. Based on information obtained from different manufacturers/distributors, diesel generators (with weather enclosures) for the size needed range in cost from $6,000 to $20,000.

Duke recently supplied a cost estimate for this type of modification in response to an RAI [Reference 6] on a severe accident mitigation alternative (SAMA) for McGuire and Catawba. The cost for equipment and materials for a small diesel generator (~5 kW), cables, circuit breakers, concrete pad, and related items was estimated to be $50,000. This cost is adopted as representative of adding one independent power supply per unit at a dual unit ice condenser plant. The cost for the TVA plants is increased by $10,000, and by $5,000 for the Mark III's to account for the larger diesel generators required.

Installation was estimated by Duke to cost $110,000/unit [Reference 6]. The installation cost is assumed to include installation of conduit or cable raceways, pulling and terminating the cable, installation of electrical panels, circuit breakers, switches, etc., pouring of a concrete pad, and anchoring of the diesel generator. The majority of this cost is attributed to the installation of conduit and cable. At the time Duke provided the estimate, the understanding was that there would be one pre-staged diesel generator with the capability of supplying power to either unit. Since that time, it has been shown that the use of two diesel generators (one per unit) is more

cost-effective than the use of one centrally located diesel generator due to the expense of installing conduit and cable [Reference 5]. Accordingly, the installation cost previously provided is adjusted by 25% to account for the reduced amount of conduit and cable that will be needed outside of the auxiliary building. An estimate for installation of conduit and cable by another utility [Reference 7] is on par with the estimate provided by Duke. Therefore, $82,500 for installation will be used in this analysis as the cost for installation.

Engineering was estimated by Duke to be $5,000 which appears to be a low figure [Reference 6]. Other SAMA evaluations, past and recent, estimate engineering costs for similar modifications to be between $50,000 and $175,000 [References 7 and 8]. A cost of $50,000 will be used for this analysis; this is applicable to single unit IC's as well as the Mark III plants. For dual unit IC's an engineering cost of $60,000 is used, or $30,000/unit.

For the generators of interest, the fuel consumption rate is between 1 and 2 gallons per hour. Based on the assumption that the diesel will be required to operate for 24 hours, 50 to 100 gallons of diesel fuel will be required. Since the diesel does not have this fuel capacity, an additional tank, or means of supplying the fuel will be necessary. The cost associated with this is expected to be minimal, about $1,000, and is included in the equipment and materials cost.

A connection/tie-in to the existing power supply to the hydrogen igniters will be necessary. The power distribution panels and motor control centers are typically located in the auxiliary building. The exposure rate for this specific location is not known; however, a dose rate of 5 mrem/hour is not unreasonable, considering the auxiliary building dose rates described in Reference 9. It is assumed that 60% of the "installation" labor occurs outside of the auxiliary building while the remainder of the labor occurs inside the auxiliary building. It is further assumed that the time spent in the auxiliary building would be about 1,120 person hours. At a cost of $2,000/person-rem, the cost for occupational exposure due to installation is approximately $11,200/unit. Dose rates outside the auxiliary building are assumed to be negligible.

According to several SAMA evaluations, the minimum cost for a procedure change and training is $30,000 [Reference 10]. This modification will require the development or modification of emergency procedures as well as training. Therefore, an estimate of $50,000 is used for this analysis. Because of possible differences between the units at a dual-unit site, the dual-unit site costs are estimated to be $60,000, or $30,000/unit.

For this case, it is assumed that the resolution of GSI-189 will be subsumed by the 10 CFR 50.44 rulemaking. Therefore, it is likely that a change to the UFSAR would be appropriate. In order to make a change to the UFSAR without prior NRC approval (which is assumed by this analysis), the licensee would need to perform a 10 CFR 50.59 evaluation. Licensee costs associated with a 50.59 evaluation and modification to the UFSAR are estimated to be $10,000. Again, as with procedure changes, the units at a dual-unit site may be sufficiently different that costs will be higher for those sites. Thus, the dual-unit costs are assumed at $12,500, or $6,250/unit. Since the proposed modification does not involve any safety-related equipment, i.e., the equipment will be Category 3, no changes to the technical specifications are expected.

The table below contains a summary of the costs for Industry Implementation.

Table 3-2 Industry Implementation - Base Case (Case 1)

Cost Element	McGuire, Catawba, and Cook (per Unit)	Sequoyah (per Unit)	Watts Bar (Single-Unit)	Mark III Plants (Single-Unit)
Materials and Equipment	$50,000	$60,000	$60,000	$55,000
Installation	$82,500	$82,500	$82,500	$82,500
Engineering	$30,000	$30,000	$50,000	$50,000
Worker Dose	$11,200	$11,200	$11,200	$11,200
Emergency Procedures	$30,000	$30,000	$50,000	$50,000
Licensing Costs	$6,250	$6,250	$10,000	$10,000
Total for Industry Implementation	$209,950	$219,950	$263,700	$258,700

Industry Operation

This attribute accounts for the projected incremental cost due to routine and recurring activities required by the proposed action on all affected licensees. The most notable costs considered are routine surveillance, maintenance and testing. Since the diesel generator will only be used in the event of SBO, periodic surveillance, testing and maintenance to ensure its operability will be necessary. Duke estimated operations and maintenance (O&M) costs for the remaining life including the license renewal period to be $40,000 [Reference 6]. Another utility estimated O&M costs for a larger generator (50 kW) and more complex system to be $100,000 [Reference 7]. This estimate was based on periodic testing requiring 3 operators for ½ shift (annually) and periodic maintenance requiring 3 mechanics for 1 shift and 2 electricians for 1 shift (annually) over a 30-year remaining life. For the purposes of this analysis, Duke's estimate of $40,000/unit will be used. As previously stated, dose rates in the test area are assumed to be negligible. Therefore, there is no occupational exposure associated with surveillance and maintenance.

NRC Implementation

This attribute measures NRC's incremental cost in implementing this regulatory change. Costs associated with a rulemaking and any review of licensee documentation are considered here. For the Base Case (Case 1), it is assumed that the resolution of GSI-189 will be included with the rulemaking effort for 10 CFR 50.44. In Reference 11, the cost estimated for a rulemaking of this type is $500,000. We assume that an additional incremental cost of $150,000 will be added to the rulemaking cost by adding the GSI-189 action. This cost will be equally shared among the 13 units involved in the GSI-189 action, thus yielding a per-unit cost of approximately $12,000.

Since the equipment is not safety-related, no changes to the technical specifications will be necessary. However, changes to the UFSAR and PRA models are expected. NRC review of the UFSAR occurs every two years Since the change will likely be submitted with the required

update, the additional NRC cost should be minimal. Furthermore, since licensees do not typically submit their PRA models to the NRC for review, no additional NRC costs are assumed.

NRC Operation

This attribute measures NRC's incremental costs after the proposed action is implemented. As a result of the proposed action, there will be an increased effort during inspections. Assuming that an additional two-hour of inspection time is required annually, the total cost for NRC operation over 40 years is estimated to be $2,000 [based on an NRR labor rate of $80/hour].

Summary of Impacts for the Base Case (Case 1)

The table below contains a summary of the impacts for the Case 1, which is considered to be the Base Case.

Table 3-3 Summary of Impacts for the Base Case (Case 1)

Attribute	McGuire, Catawba, and Cook (per Unit)	Sequoyah (per Unit)	Watts Bar (Single-Unit)	Mark III Plants (Single-Unit)
Industry Implementation	$209,950	$219,950	$263,700	$258,700
Industry Operation	$40,000	$40,000	$40,000	$40,000
NRC Implementation	$12,000	$12,000	$12,000	$12,000
NRC Operation	$2,000	$2,000	$2,000	$2,000
Total for Case 1 (Base Case)	$263,950	$273,950	$317,700	$312,700

The values in Table 3-3 are "best estimate" point values. An uncertainty assessment was also performed that considered possible variations in costs across all the cost element and cost attribute variables. The uncertainties are discussed in Section 4.

3.1.1 Sensitivity Studies

In addition to considering a low-cost version of the Base Case (Case 1), assessed as Case 2, a number of sensitivities are considered. All of these sensitivity studies are relative to the Base Case. The following evaluations were performed:

- cost if the backup power supplies are qualified for external events
- cost if GSI-189 evolves into a separate and extensive rulemaking
- cost if the industry implementation requires an extension of an outage

- cost if a 3% real discount rate is used instead of a 7% real discount rate.

3.1.1.1 Sensitivity Study 1: Alternate Power Supply and Equipment is Qualified for External Events

Since, for some of the 13 units, external events are relatively important contributors to core damage from station blackout, it is important to understand the cost implications of qualifying systems for external events. As discussed in Section 1, it is beyond the scope of this assessment to make these determinations in any detail. Not only do the external event contributors and associated magnitudes vary from site to site, but much of the external event information is qualitative (e.g., through the use of the seismic margins approach for evaluating seismic events) and not conducive to estimating costs for equipment to accommodate the external events. Thus, only a general guideline on the added costs for accommodating external events is provided.

If the alternate power supply and associated equipment (if located outdoors) are required to be qualified for external events, several of the cost elements are expected to increase significantly. Specifically, it is estimated that the cost of the materials and equipment would increase by a factor of three, the cost for installation would at least double, and the cost for engineering would double. These estimated increases are for seismic qualifications and are based on information obtained from a distributor of Class 1E electrical equipment, a national engineering laboratory that performs seismic qualifications, as well as cost estimates for severe accident mitigation alternatives submitted by license renewal applicants. All other costs are assumed to remain the same. These cost differentials are consistent with general cost trends experienced when a physical modification at a nuclear power plant is qualified for external events.

The adjusted numbers are given below. These numbers were extracted from the "Industry Implementation" table (Table 3-2) in the Base Case (Case 1) above and adjusted accordingly.

Table 3-4 Industry Implementation - Sensitivity Study: External Event Qualification

Cost Element	McGuire, Catawba, and Cook (per Unit)	Sequoyah (per Unit)	Watts Bar (Single-Unit)	Mark III Plants (Single-Unit)
Materials and Equipment	$150,000	$180,000	$180,000	$165,000
Installation	$165,000	$165,000	$165,000	$165,000
Engineering	$60,000	$60,000	$100,000	$100,000
Worker Dose	$11,200	$11,200	$11,200	$11,200

Table 3-4 (Continued)

Cost Element	McGuire, Catawba, and Cook (per Unit)	Sequoyah (per Unit)	Watts Bar (Single-Unit)	Mark III Plants (Single-Unit)
Emergency Procedures	$30,000	$30,000	$50,000	$50,000
Licensing Costs	$6,250	$6,250	$10,000	$10,000
Total for Industry Implementation	$422,450	$452,450	$516,200	$501,200

All other attributes are assumed to remain the same as in the Base Case (Case 1). The summary of attributes for external event qualification is provided in Table 3-5.

Table 3-5 Summary of Impacts for Sensitivity Study: External Event Qualification

Attribute	McGuire, Catawba, and Cook (per Unit)	Sequoyah (per Unit)	Watts Bar (Single-Unit)	Mark III Plants (Single-Unit)
Industry Implementation	$422,450	$452,450	$516,200	$501,200
Industry Operation	$40,000	$40,000	$40,000	$40,000
NRC Implementation	$12,000	$12,000	$12,000	$12,000
NRC Operation	$2,000	$2,000	$2,000	$2,000
Total for External Event Qualification	$476,450	$506,450	$570,200	$555,200

3.1.1.2 Sensitivity Study 2: If Separate Rulemaking is Required

The Base Case (Case 1) assumes that the resolution of GSI-189 will be subsumed by the 10 CFR 50.44 rulemaking. However, it is conceivable that a separate rulemaking could be pursued. For this reason, a sensitivity study is performed to assess the impact of the separate rulemaking. The cost for a simple rulemaking is estimated to be $300,000. More complex rulemakings can cost upwards of $1,000,000. It is likely that a rulemaking to resolve GSI-189, although it affects only 13 units, would likely face opposition by the industry. Therefore, a cost of $400,000 is estimated for the rulemaking. On a per unit basis, this equates to approximately $30,800. The attribute that changes is "NRC Implementation"; all other attributes are assumed to remain the same as the Base Case (Case 1).

Table 3-6 Summary of Impacts for Sensitivity Study: Rulemaking Required

Attribute	McGuire, Catawba, and Cook (per Unit)	Sequoyah (per Unit)	Watts Bar (Single-Unit)	Mark III Plants (Single-Unit)
Industry Implementation	$209,950	$219,950	$263,700	$258,700
Industry Operation	$40,000	$40,000	$40,000	$40,000
NRC Implementation	$30,800	$30,800	$30,800	$30,800
NRC Operation	$2,000	$2,000	$2,000	$2,000
Total for Rulemaking	$282,750	$292,750	$336,500	$331,500

3.1.1.3 Sensitivity Study 3: If Extended Outage is Required

Although it is not anticipated that an extended outage would be necessary to accommodate the modification(s), it is possible that limited incremental downtime during a scheduled outage might occur. For the purpose of this sensitivity analysis, an incremental downtime of 8 hours is assumed. For outages greater than or less than 8 hours, the costs stated below can be adjusted to assess the impact of a longer or shorter outage. A typical cost for an outage is $300,000 per day per unit [Reference 12], each day the unit is down. Therefore, it is expected that, for 8 hours of an extended outage, it would cost $100,000 per unit. The numbers below are extracted from the Base Case (Case 1) above, and industry implementation is adjusted to account for a one-day extended outage.

Table 3-7 Summary of Impacts for Sensitivity Study: Extended Outage

Attribute	McGuire, Catawba, and Cook (per Unit)	Sequoyah (per Unit)	Watts Bar (Single-Unit)	Mark III Plants (Single-Unit)
Industry Implementation	$309,950	$319,950	$363,700	$358,700
Industry Operation	$40,000	$40,000	$40,000	$40,000

Table 3-7 (Continued)

Attribute	McGuire, Catawba, and Cook (per Unit)	Sequoyah (per Unit)	Watts Bar (Single-Unit)	Mark III Plants (Single-Unit)
NRC Implementation	$12,000	$12,000	$12,000	$12,000
NRC Operation	$2,000	$2,000	$2,000	$2,000
Total for Sensitivity: Extended Outage	$363,950	$373,950	$417,700	$412,700

3.1.1.4 Sensitivity Study 4: If a 3% Real Discount Rate is Used

For sensitivity analysis purposes, a 3% real discount rate is recommended [Reference 2] to assess the uncertainty in the time value of money. For 40 years the present-worth multiplier is 13.42, assuming 7%. Assuming a 3% real discount rate, the multiplier becomes 23.29. Thus, for the "Operation" attributes, the Base Case (Case 1) numbers are multiplied by the ratio of these numbers (23.29/13.42), which is 1.735, to obtain the values for a 3% real discount rate. However, because the costs associated with the operation attributes are relatively small, this adjustment has a minimal effect on the total costs.

3.2 Case 2: Costs for Off-the-Shelf Backup Power to the Hydrogen Igniters for Ice Condenser and Mark III Plants During SBO Conditions

This case represents a lower bound to establish the least expensive, yet feasible modification. The Base Case assumes that an alternate ac power source to power one train of hydrogen igniters is pre-staged or permanently placed. Because of the relatively small amount of power needed to power one train of igniters, it is believed that the objective can be accomplished with a portable alternate ac power source, i.e., can be stored in a location then hooked up to the igniters via a patch panel on an as-needed basis. Some of the cost elements will remain the same (as the Base Case) such as emergency procedures and licensing. Other costs such as materials and equipment, installation and engineering will be less.

As is the case with the Base Case (Case 1), permanent modifications to the plant are necessary to accommodate the hook up of the alternate power supply.

Although this alternative to the Base Case (Case 1) is assessed here for accommodating internal events, it is important to note that portable diesel generators are designed for use at construction sites, outdoors, and the like; therefore they tend to be durable, and as such, could possibly survive external events, depending upon where and how they are stored. In the study described in Reference 4, generators are stored in a seismically bolted down storage locker in the vicinity of the connection panel. The costs for this type of storage locker are not included in this assessment.

Industry Implementation

This attribute accounts for the projected incremental cost on the affected licensees to install or implement mandated changes. Cost elements such as engineering, materials and equipment, structures, installation, occupational exposure, procedures and training are considered. Other costs elements such as planning, scheduling, and procurement are included with the engineering costs.

The general design considered which serves as the basis for this portion of the cost analysis includes an emergency patch panel. The patch panel accommodates the hook up of the portable diesel generator. For the purposes of this analysis, it is assumed that the patch panel will be installed at the exterior of the auxiliary building or within a short distance of the auxiliary building. Therefore, the amount of conduit and cable needed outside of the building is minimal, thereby reducing the cost of installation, relative to that assumed in the Base Case, which is mainly driven by the cost associated with installing conduit and cable. The remainder of the design, that which is inside the auxiliary building, is assumed to be the same as that considered for the Base Case (Case 1). Therefore, the installation costs used in the Base Case are reduced by 40 percent, which results in a per-unit installation cost of $49,500.

The materials and equipment costs associated with the portable diesel generator option are less than those used in the Base Case – $50,000 to $60,000 – (Case 1). The diesel generators considered in the Base Case are "industrial grade," and therefore, are more expensive. Based on information obtained from different manufacturers/distributors of portable diesel generators, for the sizes needed, the costs range from $2,000 to $12,000.

The cost of $12,000 is estimated for a diesel generator for the TVA plants. Because a larger diesel generator is needed for these plants (~20 kW), in order for the generator to be "portable," it would be mounted on a trailer.

Less conduit and cable will be required due to the use of the portable diesel generator as well as the proximity of the patch panel to the auxiliary building. The use of the patch panel is an additional cost; however the cost for a patch panel is $1,000 or less. As is the case with Base Case (Case 1), the portable diesel generator does not have a sufficient fuel capacity; therefore, an additional tank, or means of supplying the fuel will be necessary. The cost associated with this is expected to be minimal, about $1,000. This cost is included in the equipment and materials cost. Thus, for this analysis, the cost for equipment and material is estimated to be $25,000/unit for the dual-unit ice condenser sites (excluding TVA plants), $35,000/unit for the TVA plants, and $30,000 for the Mark III plants.

Engineering costs are expected to be less than those used in the Base Case. Since the modification inside the auxiliary building is similar for both the Base Case and this case, and since there is not expected to be a large amount of cable installed outside the auxiliary building, the engineering costs are reduced to $40,000 for dual-unit sites, and $30,000 for single-unit sites.

A connection/tie-in to the existing power supply to the hydrogen igniters will be necessary. The power distribution panels and motor control centers are typically located in the auxiliary building. This installation activity inside the auxiliary building will be similar to the Base Case however, not as extensive. The cost for occupational exposure due to installation is estimated at $8,400/unit. Dose rates outside the auxiliary building are assumed to be negligible.

According to several SAMA evaluations, the minimum cost for a procedure change and training is $30,000 [Reference 10]. This modification will require the development or modification of emergency procedures as well as training. Therefore, an estimate of $50,000 is used for this analysis for single-unit sites. Because of possible differences between the units at a dual-unit site, the dual-unit site costs are estimated to be $60,000, or $30,000/unit.

The licensing costs are assumed to be similar to those for the Base Case.

Table 3-8 Industry Implementation - Case 2

Cost Element	McGuire, Catawba, and Cook (per Unit)	Sequoyah (per Unit)	Watts Bar (Single-Unit)	Mark III Plants (Single-Unit)
Materials and Equipment	$25,000	$35,000	$35,000	$30,000
Installation	$49,500	$49,500	$49,500	$49,500
Engineering	$20,000	$20,000	$30,000	$30,000
Worker Dose	$8,400	$8,400	$8,400	$8,400
Emergency Procedures	$30,000	$30,000	$50,000	$50,000
Licensing Costs	$6,250	$6,250	$10,000	$10,000
Total for Industry Implementation	$139,150	$149,150	$182,900	$177,900

Industry Operation

This attribute accounts for the projected incremental cost due to routine and recurring activities required by the proposed action on all affected licensees. The most notable costs considered is routine surveillance, testing and maintenance. Since the diesel generator will only be used in the event of SBO, periodic surveillance, testing and maintenance to ensure its operability is likely. Duke estimated operations and maintenance (O&M) costs to be $40,000 [Reference 6]. This value is used for the purposes of this analysis. As previously stated, dose rates outside are assumed to be negligible. Therefore, there is no occupational exposure associated with surveillance and maintenance.

NRC Implementation

This attribute measures NRC's incremental cost in implementing this regulatory change. Costs associated with a rulemaking and any review of licensee documentation are considered here. It is assumed that the resolution of GSI-189 will be included with the rulemaking effort for 10 CFR 50.44. In Reference 11, the cost estimated for a rulemaking of this type is $500,000. We assume that an additional incremental cost of $150,000 will be added to the rulemaking cost by subsuming the GSI-189 action. This cost will be equally shared among the 13 units involved in the GSI-189 action, thus yielding a per-unit cost of approximately $12,000.

Since the equipment is not safety-related, no changes to the technical specifications will be necessary. However, changes to the UFSAR and PRA models are expected. NRC review of the UFSAR occurs every two years. Since the change will likely be submitted with the required update, the additional NRC cost should be minimal. Furthermore, since licensees do not typically submit their PRA models to the NRC for review, no additional NRC costs are assumed.

NRC Operation

This attribute measures NRC's incremental costs after the proposed action is implemented. As a result of the proposed action, there will be an increased effort during inspections. Assuming that an additional two hours of inspection time is required annually, the total cost for NRC operation over 40 years is estimated to be $2,000 (based on an NRR labor rate of $80/hour).

Table 3-9 Summary of Impacts for Case 2

Attribute	McGuire, Catawba, and Cook (per Unit)	Sequoyah (per Unit)	Watts Bar (Single-Unit)	Mark III Plants (Single-Unit)
Industry Implementation	$139,150	$149,150	$182,900	$177,900
Industry Operation	$40,000	$40,000	$40,000	$40,000
NRC Implementation	$12,000	$12,000	$12,000	$12,000
NRC Operation	$2,000	$2,000	$2,000	$2,000
Total for Case 2	$193,150	$203,150	$236,900	$231,900

3.3 Case 3: Costs for Backup Power to the Hydrogen Igniters and Air Return Fans for Ice Condenser Plants Under SBO Conditions

This case is similar to the Base Case (Case 1) with the exception of the size of the diesel generator required, and it only applies to plants with ice condenser containments. Other information pertinent to powering an air return fan (ARF) in addition to one train of igniters is discussed below. As is considered for the Base Case, each unit will be supplied with a diesel generator.

The existing power supply to the ARFs is Class 1E, and typically rated at 480 V. The exact tie-in to the existing power supply would be plant specific, but for this case is assumed to occur at the 480 V motor control center or comparable power panel. Therefore, the rating of the generator would be 480 V. The typical power needed for one train of igniters at McGuire, Catawba and Cook plants is 4,400 watts and 20.4 kW for the TVA plants as indicated in Table 3-1. Air return fans require between 20 and 30 kW of power. Therefore, the size of the generator needed to power one train of igniters and one ARF is between 25 and 50 kW. It is anticipated that the ARF will be energized before the igniters are energized. This sequencing allows for the containment atmosphere to mix before activating the igniters. Further, it allows for more generator power to be available to the ARF during startup, when the ARF motor will draw more current.

Along with the assumptions above, the following is assumed.

- the igniters and air return fan will be required to run for 24 hours, and
- all modifications can be made on-line or during a planned outage.

Industry Implementation

This attribute accounts for the projected incremental cost on the affected licensees to install or implement mandated changes.

Based on information obtained from different manufacturers/distributors, diesel generators (with weather enclosures) for the size needed at a 480 V rating are estimated to be between $15,000 and $50,000.

Duke recently supplied a cost estimate for this type of modification in response to an RAI [Reference 6] on a severe accident mitigation alternative (SAMA) for McGuire and Catawba. The cost for equipment and materials for a larger diesel generator (~30 kW), cables, circuit breakers, concrete pad, and other was estimated to be $210,000.

Installation was estimated by Duke to cost $240,000. The additional $100,000 for installation (compared with the Base Case (Case 1)) is assumed to be for routing of cable, installation of switches and other components for the ARF. As explained in Case 1, it has been shown that the use of two diesel generators (one per unit) is more cost-effective than the use of one centrally located diesel generator due to the expense of installing conduit and cable. Therefore, to account for the reduction in the amount of conduit and cable needed outside of the auxiliary building, the installation cost previously provided is reduced by 25%, to $180,000/unit.

Engineering was estimated by Duke to be $50,000/unit, or $100,000 per station. For a single-unit site (Watts Bar), this estimate is reduced to $75,000.

For the generators of interest, the fuel consumption rate is between 5 and 7 gallons per hour. Based on the assumption that the diesel will be required to operate for 24 hours, 120 to 168 gallons of diesel fuel will be required. Since the diesel generator does not have this fuel capacity, an additional tank, or means of supplying the fuel will be necessary. The cost associated with this is expected to be minimal (approximately $2,000). This estimate is double the estimate used in the Base Case (Case 1). The cost is added to the Materials and Equipment costs discussed above.

A connection/tie-in to the existing power supply to the igniters and ARF will be necessary. The power distribution panels and motor control centers are typically located in the auxiliary building. The exposure rate for this specific location is not known; however, a dose rate of 5 mrem/hour is not unreasonable, considering the auxiliary building dose rates described in Reference 9. Dose rates outside the auxiliary building are assumed to be negligible. At a cost of $2,000/person-rem, the cost for occupational exposure due to installation is estimated to be $24,500/unit. The increase in dose relative to the Base Case (Case 1) is primarily due to the fact that there will be an increase in time in the auxiliary building in order to install conduit, cable, switches, and circuit breakers for the ARF.

According to several SAMA evaluations, the minimum cost for a procedure change and training is $30,000 [Reference 10]. This modification will require the development or modification of emergency procedures as well as training. Therefore, an estimate of $50,000 is used for this

analysis for a single-unit site. Because of possible differences between the units at a dual-unit site, the dual-unit site costs are estimated to be $60,000, or $30,000/unit.

For this case, it is assumed that the resolution of GSI-189 will be subsumed by the 10 CFR 50.44 rulemaking. Therefore, it is likely that a change to the UFSAR would be appropriate. Licensee costs associated with a modification of this nature to the UFSAR are typically between $10,000 and $15,000. For the purposes of this analysis, an estimate of $12,500 for the dual-unit sites, and $10,000 for the single-unit site is used. Since the proposed modification does not involve any safety-related equipment, i.e., the equipment will be Category 3, no changes to the Technical Specifications are expected.

Table 3-10 Industry Implementation - Case 3

Cost Element	McGuire, Catawba, and Cook (per Unit)	Sequoyah (per Unit)	Watts Bar (Single-Unit)
Materials and Equipment	$212,000	$262,000	$262,000
Installation	$180,000	$180,000	$180,000
Engineering	$50,000	$50,000	$75,000
Worker Dose	$24,500	$24,500	$24,500
Emergency Procedures	$30,000	$30,000	$50,000
Licensing Costs	$6,250	$6,250	$10,000
Total for Industry Implementation	$502,750	$552,750	$601,500

Industry Operation

This attribute accounts for the projected incremental cost due to routine and recurring activities required by the proposed action on all affected licensees. The costs for industry operation at IC plants are increased (from the Base Case) to account for additional time needed to test the ARF and sequencing.

NRC Implementation

This attribute measures NRC's incremental cost for the rulemaking effort associated with implementing this regulatory change. The costs for NRC implementation are assumed to be the same as for the Base Case (Case 1), except that only the nine ice condenser units are considered. Thus, the cost of NRC implementation, namely $150,000, is divided by 9 units, yielding approximately $17,000 per unit.

NRC Operation

This attribute measures NRC's incremental costs after the proposed action is implemented. As a result of the proposed action, there will be an increased effort during inspections. The costs for NRC operation are assumed to be the same as for the Base Case (Case 1).

Table 3-11 Summary of Impacts for Case 3

Attribute	McGuire, Catawba, and Cook (per Unit)	Sequoyah (per Unit)	Watts Bar (Single-Unit)
Industry Implementation	$502,750	$552,750	$601,500
Industry Operation	$50,000	$50,000	$50,000
NRC Implementation	$17,000	$17,000	$17,000
NRC Operation	$2,000	$2,000	$2,000
Total for Case 3	$571,750	$621,750	$670,500

3.4 Case 4: Costs for Passive Autocatalytic Recombiners (PARs) for Ice Condenser and Mark III Plants Under SBO Conditions

This case considers installation of PARs in containment. Much of the information provided below is taken from Reference 11 and adjusted to reflect the containment designs of consideration.

Industry Implementation

This attribute accounts for the projected incremental cost on the affected licensees to install or implement mandated changes. It is estimated that an average of 40 half-sized PARs would be installed in each ice condenser and Mark III containment. The average purchase price per half-sized PAR is estimated to be $24,000 [Reference 13]. Although the ability exists to produce PARs domestically, currently, PARs are imported from Europe. The amount above is based on the cost of an imported PAR. Thus, the purchase cost equates to $960,000. Should a catalyst bed need to be replaced (due to test failure), a replacement bed would cost approximately $350 [Reference 13]. A few beds are likely to be purchased at the time the PARs are purchased. Therefore, an additional cost of $1,000/unit is likely. The catalyst beds need to be tested in a testing enclosure complete with sensing instrumentation and a computer. The current cost for such a testing apparatus is $10,000. Each plant would require a testing apparatus. Thus, the total estimated Materials and Equipment element for a single-unit site is $960,000 + $1,000 + $10,000 = $971,000. The corresponding total for the dual-unit sites is 2x($960,000) + 2x($1,000) + $10,000 = $1,932,000.

Installation costs will also vary depending on the area of the country (differing labor rates) in which the plant is located. At Indian Point 2, it cost approximately $100,000 to install two full-sized PARs [Reference 13]. Although the cost for installing 40 PARs is not expected to increase by 20 times, it is expected to increase by a factor of five (based on economies of scale). Thus, total labor costs are expected to be $500,000 per unit.

The engineering associated with installation of the PARs will vary depending on the intended location of the PARs and whether extensive modifications will be necessary to accommodate the PARs. Based on information provided in past SAMA evaluations, a recent response to a Request for Additional Information related to SAMA evaluations, and information obtained from Indian Point 2, engineering costs ranged from $35,000 to $400,000 [References 8, 13]. Assuming units at dual-unit sites are similar in design and layout, our estimate for engineering of

the PARS is $150,000 which is independent of whether it is a single or dual unit site. This estimate is largely driven by the fact that the PARs will have to be seismically installed.

During installation, workers are expected to receive occupational doses. The dose rates assumed are based on those given for recombiners in Reference 9, which are 10 mrem/hour for PWRs and 20 mrem/hour for BWRs. For this assessment, an average of 15 mrem/hour will be used. Since many, if not all, of the PARs will be seismically installed, it is estimated that it will take two men 24 hours per PAR. At the dose rate assumed for 40 PARs, this equates to 28.8 person-rem. The total cost for occupational exposure is estimated to be $57,600 per unit.

The PARs, most probably, will be maintained as Category 3 components (as defined in Reference 3). Testing and surveillance, although not required, would be recommended. A testing/surveillance procedure would need to be developed. Industry estimates for development of a procedure and its implementation (i.e., training) are a minimum of $30,000 [Reference 10]. However, the procedure for testing the PARs is not as complex as other procedures (such as emergency operating procedures), and has already been developed for Indian Point 2. The effort at Indian Point 2 cost approximately $2,000 [Reference 13]. However, this included the training of only two individuals. Since for the purposes of this analysis 40 PARs are going to be installed, it is likely that more than two individuals would be trained. Therefore, the estimated cost for developing and implementing the testing procedure at a typical plant is estimated to cost $3,000.

For this case, it is assumed that the resolution of GSI-189 will be subsumed by the 10 CFR 50.44 rulemaking. Therefore, it is likely that a change to the UFSAR would be appropriate. Licensee costs associated with a modification of this nature to the UFSAR are typically between $10,000 and $15,000. Here $12,500 for dual-unit sites and $10,000 for single-unit sites is assumed. Since the proposed modification does not involve any safety-related equipment, i.e., the equipment will be Category 3, no changes to the Technical Specifications are expected.

Table 3-12 Industry Implementation - Case 4

Cost Element	McGuire, Catawba, and Cook (per Unit)	Sequoyah (per Unit)	Watts Bar (Single-Unit)	Mark III Plants (Single-Unit)
Materials and Equipment	$966,000*	$966,000*	$971,000	$971,000
Installation	$500,000	$500,000	$500,000	$500,000
Engineering	$75,000**	$75,000**	$150,000	$150,000
Worker Dose	$57,600	$57,600	$57,600	$57,600

Table 3-12 (Continued)

Attribute	McGuire, Catawba, and Cook (per Unit)	Sequoyah (per Unit)	Watts Bar (Single-Unit)	Mark III Plants (Single-Unit)
Emergency Procedures	$1,500	$1,500	$3,000	$3,000
Licensing Costs	$6,250	$6,250	$10,000	$10,000
Total for Industry Implementation	$1,606,350	$1,606,350	$1,691,600	$1,691,600

*Assumes testing apparatus is shared by both units
**Assumes units are similar in design and layout

Industry Operation

This attribute accounts for the projected incremental cost due to routine and recurring activities required by the proposed action on all affected licensees.

The only expected operation costs associated with the PARs after installation will be due to testing. One catalyst bed per PAR should be tested periodically. It is estimated that it will take a technician 0.5 hour to remove a catalyst bed, observe the PAR for any fouling (accumulation of dirt, debris, dust), then reinstall it after testing [Reference 13]. The total time estimated for performing the test, including transportation time, paper work, etc., is one hour per PAR [Reference 13]. This process involves two persons. Therefore, the total labor cost involved with testing a PAR is estimated to be $200/PAR, assuming a labor rate of $100/hour [Reference 13]. Since it is recommended that 1/4th of the PARs be tested every refueling outage [Reference 13], this equates to approximately $1,333 per year per plant based on an 18-month refueling cycle. Using the multiplier of 13.42 to determine the year 2002 cost equivalent, the cost is $18,000.

Testing also involves the passing of a known concentration of hydrogen gas across the catalyst bed. A cylinder of hydrogen would be required to perform the testing. At Indian Point 2, it cost approximately $100/PAR for the hydrogen [Reference 13]. Therefore, at a PWR considered by this analysis, the cost for hydrogen per year is estimated to be $700 ($100/PAR x 10 x 12/18 = $667). Again, using the multiplier of 13.42 to determine the year 2002 cost equivalent, the cost is $9,400.

The last expected cost associated with testing of the PARs is a calibration of the testing unit once every six years. Assuming 7 tests over the 40 year remaining life of the plant and a cost per test of $3,000, the approximate cost for calibration will be approximately $10,000.

NRC Implementation

This attribute measures NRC's incremental cost in implementing this regulatory change. Costs associated with a rulemaking and any review of licensee documentation are considered here. For Case 4, it is assumed that the resolution of GSI-189 will be included with the rulemaking effort for 10 CFR 50.44. In Reference 11, the cost estimated for a rulemaking of this type is $500,000. We assume that an additional incremental cost of $150,000 will be added to the

rulemaking cost by adding the GSI-189 action. This cost will be equally shared among the 13 units involved in the GSI-189 action, thus yielding a per-unit cost of approximately $12,000.

Since the equipment is not safety-related, no changes to the technical specifications will be necessary. However, changes to the UFSAR and PRA models are expected. NRC review of the UFSAR occurs every two years. Since the change will likely be submitted with the required update, the additional NRC cost should be minimal. Furthermore, since licensees do not typically submit their PRA models to the NRC for review, no additional NRC costs are assumed.

NRC Operation

This attribute measures NRC's incremental costs after the proposed action is implemented. As a result of the proposed action, there will be an increased effort during inspections. This Increase is expected to be small, and not quantified in detail for the purposes of this analysis. An additional inspection cost of about $1,000/year is not unreasonable. Thus, the 2002 cost equivalent is $13,400.

Table 3-13 Summary of Impacts for Case 4

Attribute	McGuire, Catawba, and Cook (per Unit)	Sequoyah (per Unit)	Watts Bar (Single-Unit)	Mark III Plants (Single-Unit)
Industry Implementation	$1,606,350	$1,606,350	$1,691,600	$1,691,600
Industry Operation	$37,400	$37,400	$37,400	$37,400
NRC Implementation	$12,000	$12,000	$12,000	$12,000
NRC Operation	$13,400	$13,400	$13,400	$13,400
Total for Case 4	$1,669,150	$1,669,150	$1,754,400	$1,754,400

4. Uncertainty

The uncertainty analysis was performed using simulation technique supported by @RISK software [Reference 14]. This software operates in Microsoft Excel environment. The uncertainty in the value of the parameters of the cost model was characterized using a triangular distribution with three points -- minimum, most likely value (the values in Tables 3-2, 3-3 and 3-8 through 3-11) and maximum. The uncertainty analysis accounted for the correlation among the parameters of the cost model.

A summary of the uncertainty assessment is provided in Table 4-1.

Table 4-1 Summary of Uncertainty Assessment

Uncertainties		McGuire, Catawba, and Cook (per Unit)	Sequoyah (per Unit)	Watts Bar (Single-Unit)	Mark III BWRs (Single-Unit)
Base Case (Case 1)	95th%	$375,000	$387,000	$464,000	$459,000
	mean	$316,000	$329,000	$387,000	$380,000
	5th%	$262,000	$274,000	$315,000	$308,000
Portable Diesel (Case 2)	95th%	$271,000	$282,000	$331,000	$326,000
	mean	$225,000	$237,000	$278,000	$272,000
	5th%	$185,000	$196,000	$230,000	$222,000
Igniters + ARFs (Case 3)	95th%	$715,000	$785,000	$830,000	N/A
	mean	$611,000	$689,000	$738,000	N/A
	5th%	$506,000	$602,000	$652,000	N/A

It is noted that the best-estimate values provided in Tables 3-3, 3-9, and 3-11 are consistently less than the mean values provided in the uncertainty analysis. This is due to the triangular distributions being skewed to higher costs.

Plots of the uncertainty distribution for the four classes of plants for the Base Case and for the two option cases are provided in the Appendix. In addition, the input assumptions are also provided.

5. Results

The best-estimate results are presented in table format below. Note that the "sensitivity" cases reflect changes to the Base Case (Case 1).

Table 5-1 Summary of Results

Case	McGuire, Catawba, and Cook (per Unit)	Sequoyah (per Unit)	Watts Bar (Single-Unit)	Mark III Plants (Single-Unit)	Industry*
Case 1: Base Case	$263,950	$273,950	$317,700	$312,700	$3,700,100
Sensitivity 1: External Event	$476,450	$506,450	$570,200	$555,200	$6,662,600
Sensitivity 2: Rulemaking	$282,750	$292,750	$336,500	$331,500	$3,944,500

Table 5-1 (Continued)

Case	McGuire, Catawba, and Cook (per Unit)	Sequoyah (per Unit)	Watts Bar (Single-Unit)	Mark III Plants (Single-Unit)	Industry*
Sensitivity 3: Extended Outage	$363,950	$373,950	$417,700	$412,700	$5,000,100
Case 2: Low Cost Fix	$193,150	$203,150	$236,900	$231,900	$2,729,700
Case 3: Igniters + ARF	$571,750	$621,750	$670,500	NA	$5,344,500
Case 4: PARs	$1,669,150	$1,669,150	$1,754,400	$1,754,400	$22,125,200

* 8 IC units at dual-unit sites, 1 IC unit at single-unit site, and 4 Mark III units at single-unit sites, except for Case 3, where the 4 Mark III units are not included.

It should be noted that the significant figures indicated in the results are retained only to allow for cross-checking and independent verification. When considering uncertainties, one significant figure would be more appropriate. For example, the "Industry" cost for the Base Case (Case 1) is about $4M and the cost approximately doubles to $7M when including external event capability.

- The total industry cost (cost for 13 units) for the Base Case (Case 1) is about $4M
- The cost about doubles to $7M when the backup power supply is qualified for external events
- Including a separate rulemaking only increases the cost (relative to the Base Case) by 8%
- If 8 hours of incremental outage time is assumed, the costs increase by about 35% (again, relative to the Base Case)
- There is virtually no additional cost when changing the real discount rate from 7% to 3%
- The "portable generator" option yields a cost that is about 75% of the Base Case cost.
- The cost for the ice condenser PWRs increases by more than 40% when the powering of an air-return fan is required.
- The cost for PARS is about 6 times higher than backup power under Base Case assumptions.
- The differences in the functional reliability between the pre-staged and the portable generators is not significant for cost benefit applications.
- The mean values for the costs are typically 8% to 25% higher than the corresponding best-estimate (most likely) costs.

6. References

1. "Regulatory Analysis Guidelines of the U.S. NRC," NUREG/BR-0058, Rev. 3, U.S. NRC, July 2000.

2. "Regulatory Analysis Technical Evaluation Handbook," NUREG/BR-0184, U.S. NRC, January 1997.
3. "Instrumentation for Light-Water-Cooled Nuclear power plants to Assess Plant and Environs Conditions during and following an Accident," Regulatory Guide 1.97, Revision 3, May 1983.
4. Moieni, P. et al., "A PRA-Based Design Change at SONGs Units 2 & 3: Add Portable Gasoline-Powered Generators for Risk Reduction," (to be published), International Topical Meeting on Probabilistic Safety Assessment, October 6-9, 2002.
5. Letter from M. S. Tuckman, Duke, to Document Control Desk, USNRC, Subject: Comments on draft plant-specific Supplement 9 to NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants" Catawba Nuclear Station, Docket Nos. 50-413 and 50-414, August 9, 2002. [ML022270455]
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7. Note from Andrew J. Kugler, USNRC, to File, Subject: Information Provided by Virginia Electric and Power Company in Relation to Severe Accident Mitigation Alternatives in its License Renewal Application for the North Anna Power Station, Units 1 and 2 (TAC Nos. MB1994 and MB1995), February 11, 2002. [ML020430372]
8. *Applicant's Environmental Report - Operating License Renewal Stage, Ft. Calhoun.* Omaha, NE, January 2002.
9. Beal, S.K., et al., "Data Base of System-Average Dose Rates at Nuclear Power Plants," Final Report, NUREG/CR-5035, October 1987.
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APPENDIX

UNCERTAINTY ANALYSIS

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UNCERTAINTY ANALYSIS

An uncertainty assessment was performed for Case 1 (Base Case); Case 2 (Portable Generator Case) and Case 3 (Igniters plus ARF Case) using Monte Carlo simulation software, @RISK. For each of these three cases, the uncertainty profile was assessed for each of the four classes of plants under study, namely (1) Catawba, McGuire, and D.C. Cook -- six units total; (2) Sequoyah -- two units total; (3) Watts Bar – one single unit; and (4) the four single-unit MARK IIIs. The results are portrayed graphically in Figures A-1 through A-11 and are summarized in Table A-1. In addition, the industry total costs are displayed in Figures A-12 through A-14. The 95th percentile value (95% confidence that the cost is less than the value), the Mean value, and the 5th percentile value (5% confidence that the cost is less than the value) are displayed.

It is noted that the best-estimate values (most likely values) provided in Tables 3-3, 3-9, and 3-11 of the report are consistently less than the mean values provided in the uncertainty analysis. This is due to the triangular distributions, which are employed to characterize uncertainty in cost estimates, being skewed to higher costs.

A summary of the uncertainty assessment is provided in Table A-1.

Table A-1 Summary of Uncertainty Assessment

Uncertainties		McGuire, Catawba, and Cook (per Unit)	Sequoyah (per Unit)	Watts Bar (Single-Unit)	Mark III BWRs (Single-Unit)
Base Case (Case 1)	95th%	$375,000	$387,000	$464,000	$459,000
	mean	$316,000	$329,000	$387,000	$380,000
	5th%	$262,000	$274,000	$315,000	$308,000
Portable Diesel (Case 2)	95th%	$271,000	$282,000	$331,000	$326,000
	mean	$225,000	$237,000	$278,000	$272,000
	5th%	$185,000	$196,000	$230,000	$222,000
Igniters + ARFs (Case 3)	95th%	$715,000	$785,000	$830,000	N/A
	mean	$611,000	$689,000	$738,000	N/A
	5th%	$506,000	$602,000	$652,000	N/A

This software operates in Microsoft Excel environment. The uncertainty in the value of the parameters of the cost model was characterized using a triangular distribution with three points -- minimum, most likely value (the values in Tables 3-2, 3-3, and 3-8 through 3-11 in the report) and maximum. The uncertainty analysis accounted for the dependency among the parameters of the cost model. Tables A-2 through A-4 provide the input data for the analyses.

Table A-2 Input for Uncertainty Analysis: Base Case

Cost Element	Dual Unit ICs (DU)	Sequoyah (SQ)	Watts Bar (WB)	Mark III (M3)
Materials and Equipment				
low	$40,000	$50,000		$45,000
most likely	$50,000	$60,000		$55,000
high	$80,000	$100,000		$90,000
Comments on range (see note below)	range is defined using Duke's data	range is modified for these plants		
Installation				
low	$70,125			
most likely	$82,500			
high	$144,375			
Comments on range	range is defined using Duke's data			
Engineering				
low	$3,000		$5,000	
most likely	$30,000		$50,000	
high	$100,000		$175,000	
Comments on range	range is modified for this type of plants		range is defined using SAMAs data	
Worker Dose (calculated)				
point estimate	$11,220			
Comments on calculation	The above value is calculated using the expression shown below which is defined in terms of four uncertain parameters (1) Installation cost, (2) dose rate, (3) hourly labor rate, and (4) % exposure			
	$\frac{\text{installation cost}}{\text{hourly rate}} \times \text{dose rate} \times \%\ \text{exposure time} \times \$2000$			
	Installation cost	Range defined above	**hourly labor rate**	
			low	$30
			most likely	$40
			high	$50
	dose rate (rem)		**% of exposure time**	
	low	0 002	low	20%
	most likely	0 005	most likely	40%
	high	0 01	high	60%
Emergency Procedures				
low	$20,000		$30,000	
most likely	$30,000		$50,000	
high	$42,500		$75,000	
Comments on range	range is modified for this type of plants		range is defined using SAMAs	
Licensing Costs				
low	$3,750		$5,000	
most likely	$6,250		$10,000	
high	$8,750		$15,000	
Comments on range	range is modified for this type of plants		range is defined using staff experience in performing 50.59	
Industry Operation				
low	$10,000			
most likely	$40,000			
high	$100,000			
Comments on range	range is defined using Duke's data and Dominion SAMA			
NRC Implementation				
low	$10,200			
most likely	$12,000			
high	$21,000			
Comments on range	range is defined based on 50 44 rulemaking			
NRC Operation				
low	$1,700			
most likely	$2,000			
high	$3,500			
Comments on range	range reflects uncertainty in the cost for increase in inspection accounting for 40 years of remaining life			

Note: the uncertainty in the value of the parameters of the cost model was characterized using a triangular distribution with three points -- low, most likely value and high

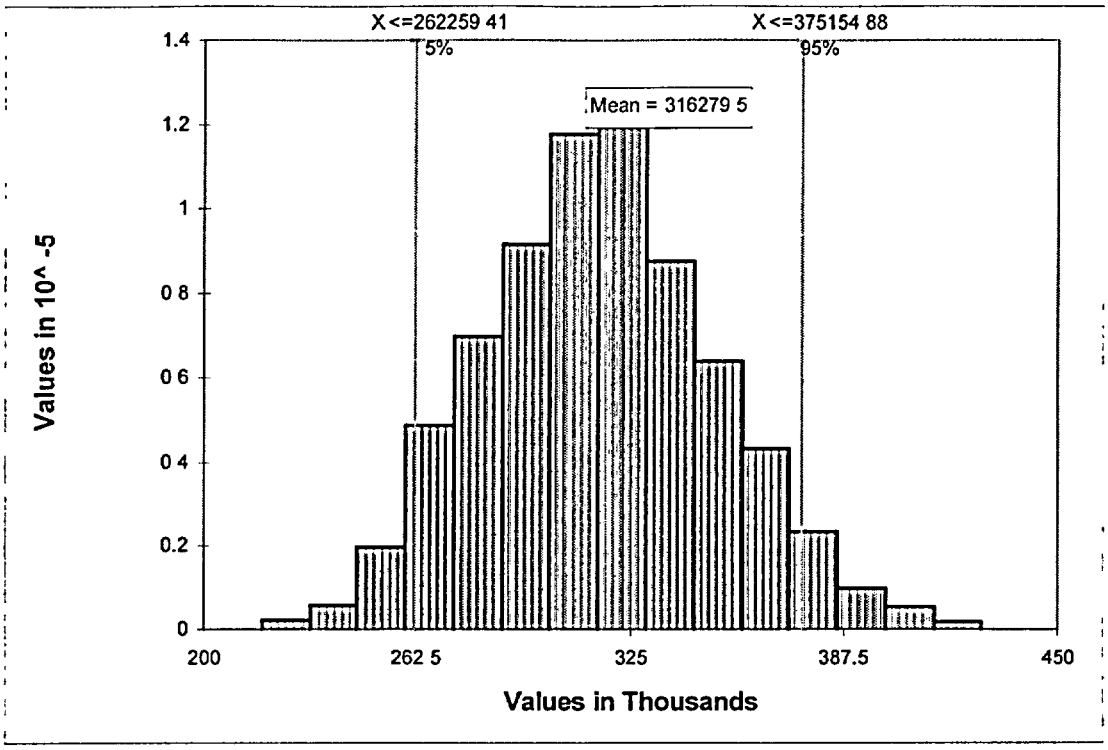

Figure A-1 Distribution for Total Cost for McGuire, Catawba, and Cook (per unit): Base Case (Pre-Staged)

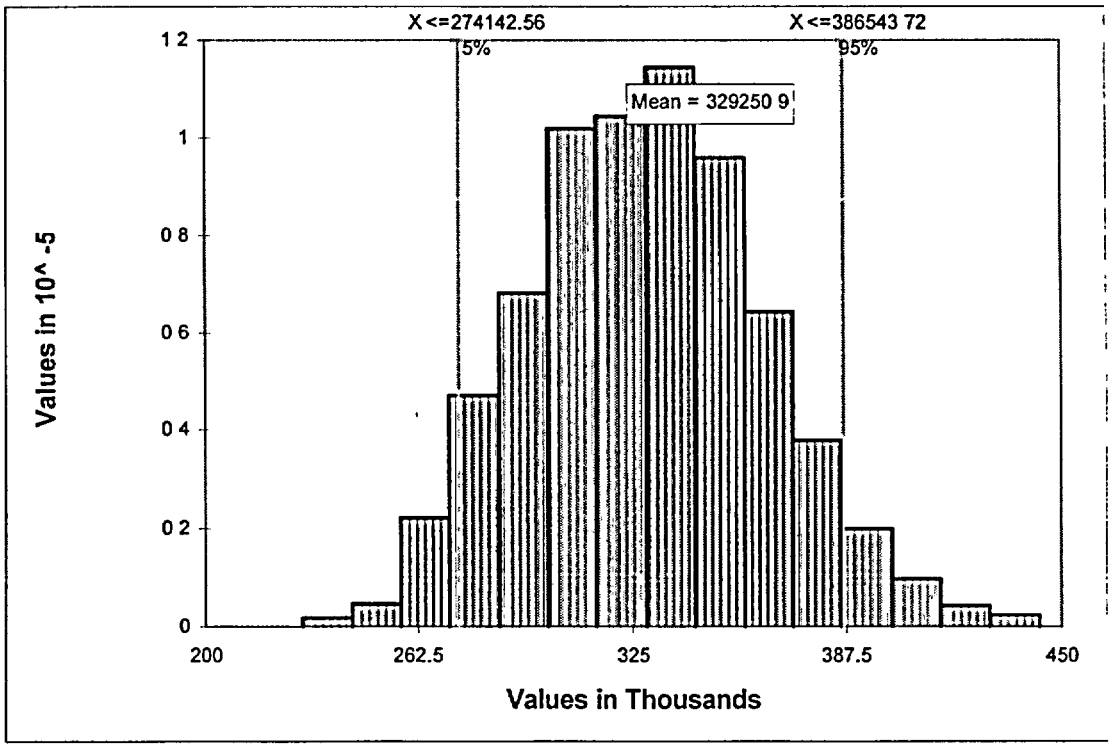

Figure A-2 Distribution for Total Cost for Sequoyah (per unit): Base Case (Pre-Staged)

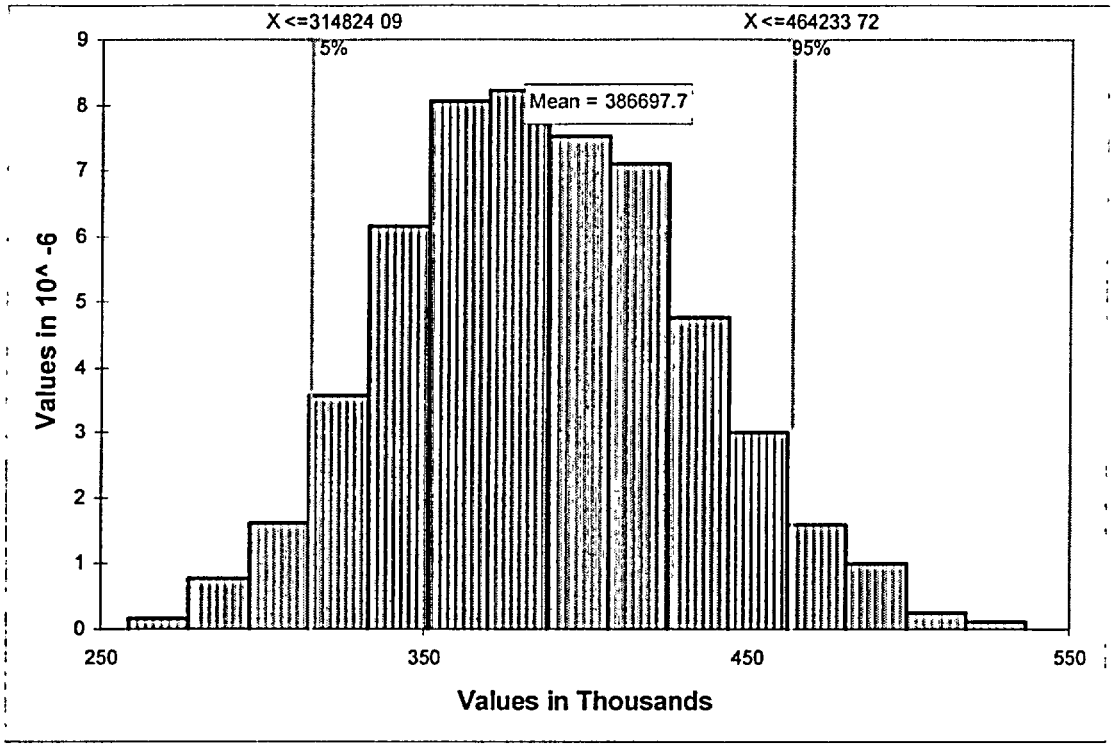

Figure A-3 Distribution for Total Cost for Watts Bar: Base Case (Pre-Staged)

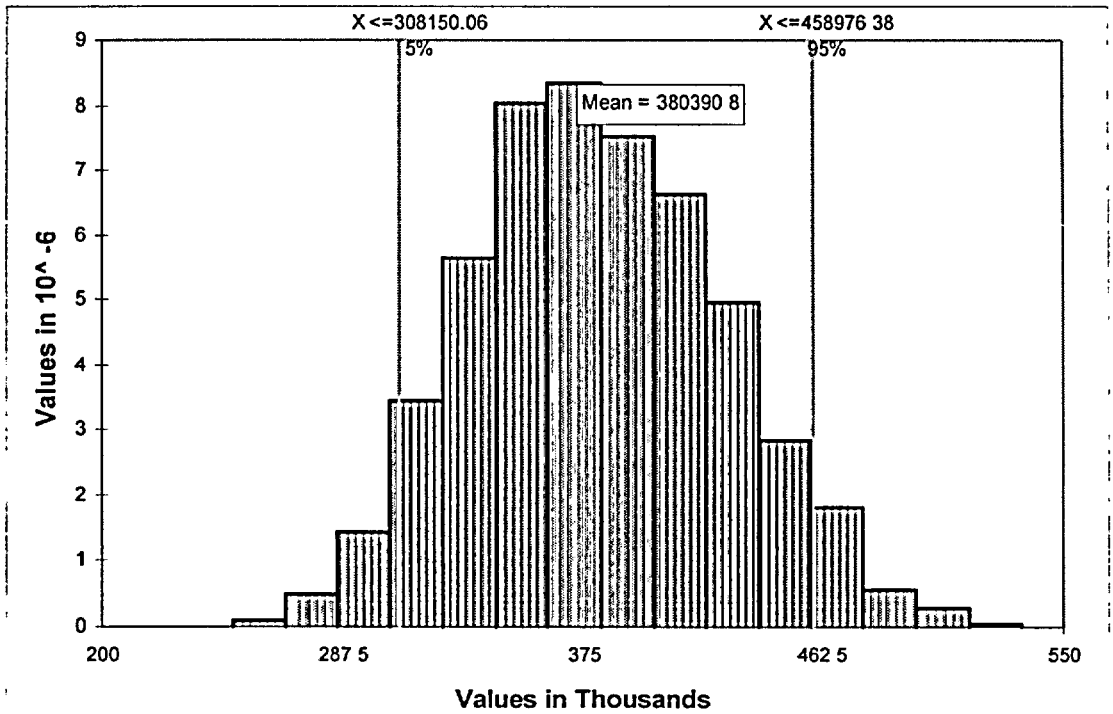

Figure A-4 Distribution for Total Cost for Mark IIIs: Base Case (Pre-Staged)

Table A-3 Input for Uncertainty Analysis: Case 2 (Portable Diesel)

Cost Element	Dual Unit ICs (DU)	Sequoyah (SQ)	Watts Bar (WB)	Mark III (M3)
Materials and Equipment				
low	$10,000	$25,000		$17,500
most likely	$25,000	$35,000		$30,000
high	$40,000	$50,000		$45,000
Comments on range (see note below)	range is defined using Duke's data	range is modified for these plants		
Installation				
low	$42,075			
most likely	$49,500			
high	$86,625			
Comments on range	range is defined using Duke's data			
Engineering				
low	$3,000		$5,000	
most likely	$20,000		$30,000	
high	$62,500		$100,000	
Comments on range	range is modified for this type of plants		range is defined using SAMAs data	
Worker Dose (calculated)				
point estimate	$8,415			
Comments on calculation	The above value is calculated using the expression shown below which is defined in terms of four uncertain parameters (1) Installation cost, (2) dose rate, (3) hourly labor rate, and (4) % exposure			
	$\frac{\text{installation cost}}{\text{hourly rate}} \times \text{dose rate} \times \%\ \text{exposure time} \times \$2000$			
	Installation cost	Range defined above	**hourly labor rate**	
			low	$30
			most likely	$40
			high	$50
	dose rate (rem)		**% of exposure time**	
	low	0 002	low	30%
	most likely	0 005	most likely	50%
	high	0 01	high	70%
Emergency Procedures				
low	$20,000		$30,000	
most likely	$30,000		$50,000	
high	$42,500		$75,000	
Comments on range	range is modified for this type of plants		range is defined using SAMAs	
Licensing Costs				
low	$3,750		$5,000	
most likely	$6,250		$10,000	
high	$8,750		$15,000	
Comments on range	range is modified for this type of plants		range is defined using staff experience in perfoming 50.59	
Industry Operation				
low	$10,000			
most likely	$40,000			
high	$100,000			
Comments on range	range is defined using Duke's data and Dominion SAMA			
NRC Implementation				
low	$10,200			
most likely	$12,000			
high	$21,000			
Comments on range	range is defined based on 50 44 rulemaking			
NRC Operation				
low	$1,700			
most likely	$2,000			
high	$3,500			
Comments on range	range reflects uncertainty in the cost for increase in inspection accounting for 40 years of remaining life			

Note: the uncertainty in the value of the parameters of the cost model was characterized using a triangular distribution with three points -- low, most likely value and high

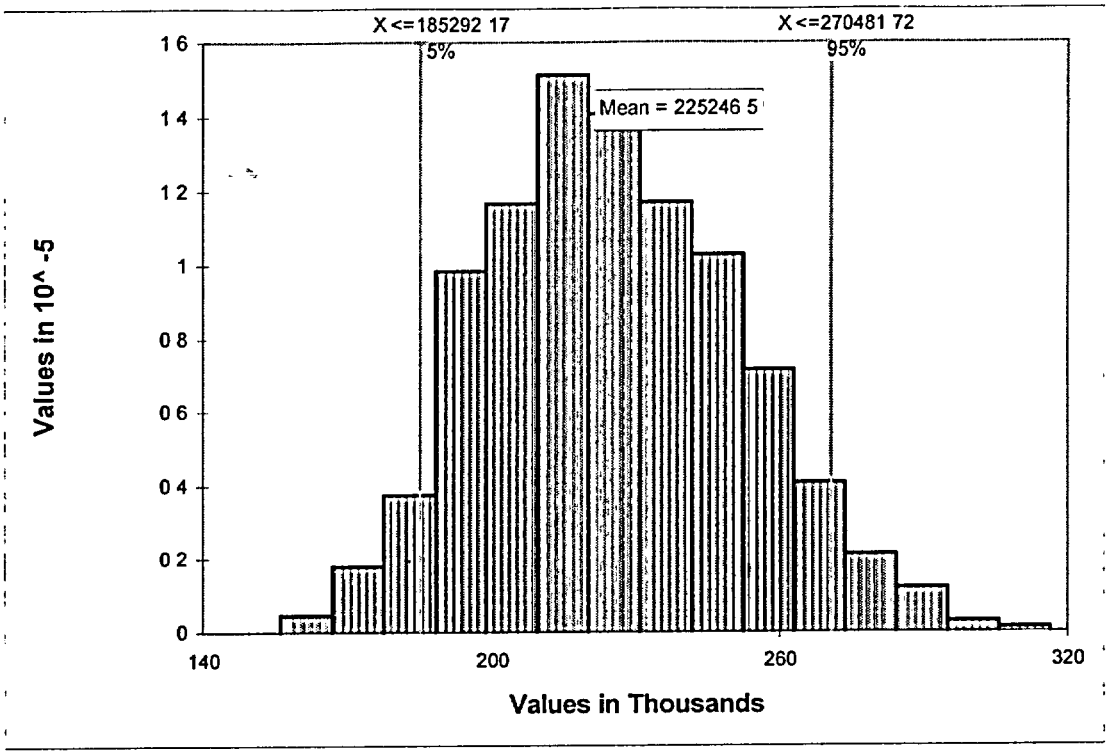

Figure A-5 Distribution for Total Cost for McGuire, Catawba, and Cook (per unit): Case 2 (Portable Diesel)

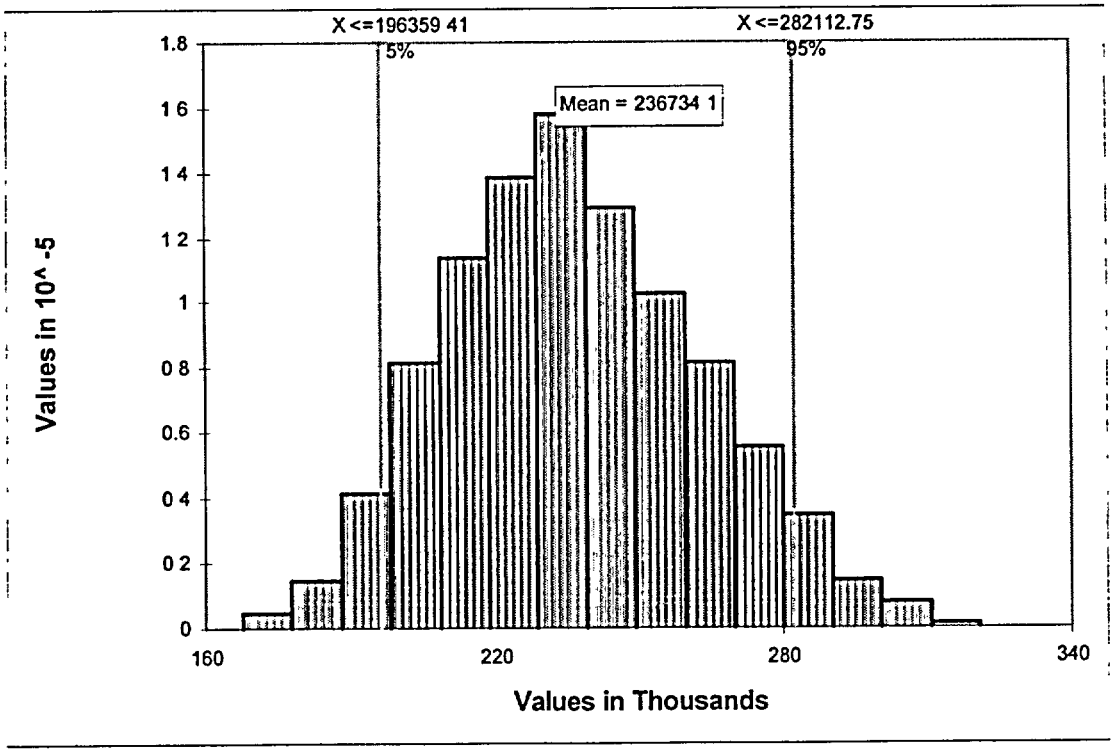

Figure A-6 Distribution for Total Cost for Sequoyah (per unit): Case 2 (Portable Diesel)

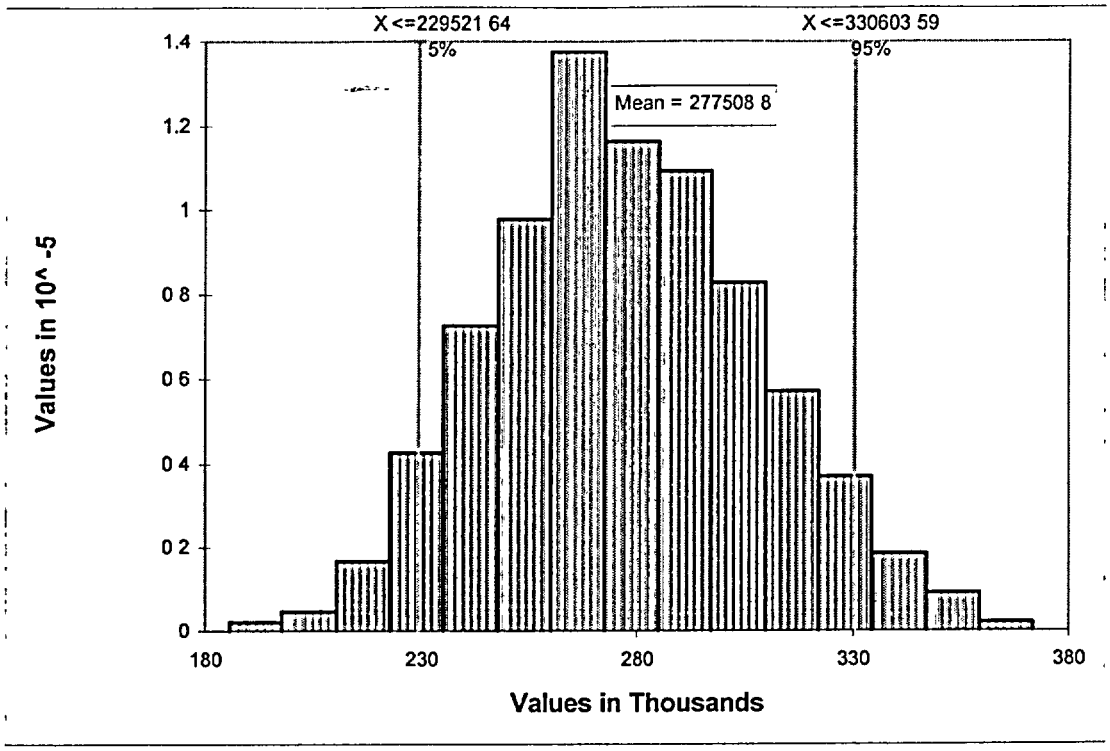

Figure A-7 Distribution for Total Cost for Watts Bar: Case 2 (Portable Diesel)

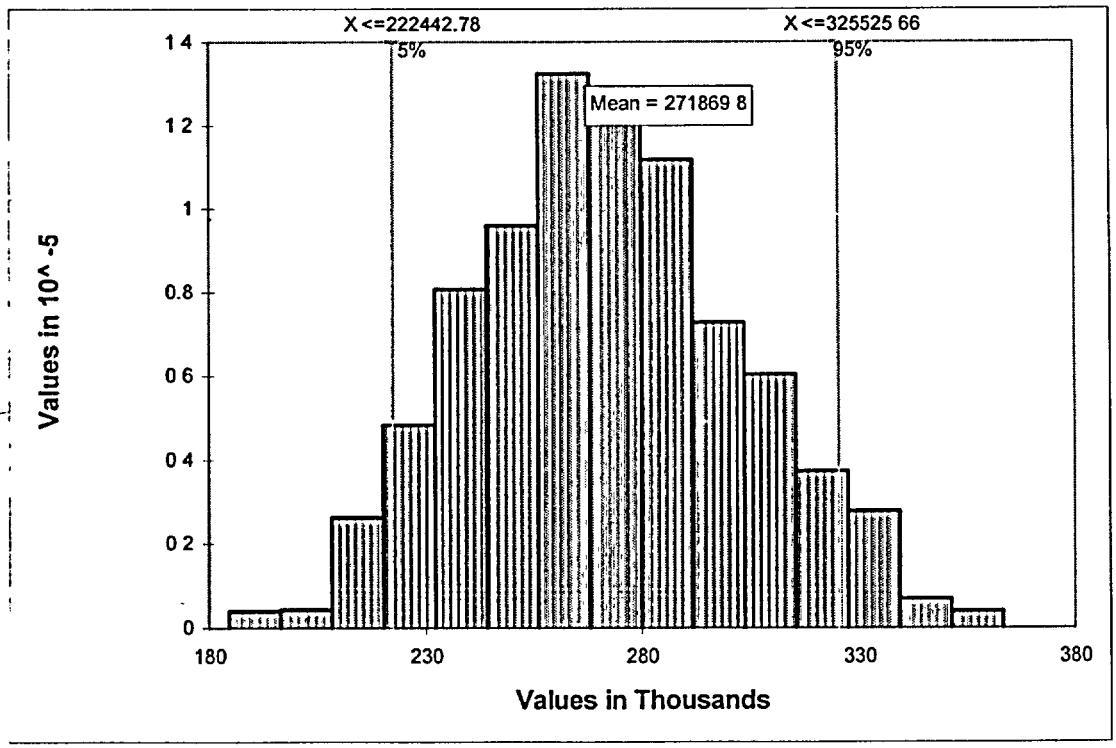

Figure A-8 Distribution for Total Cost for Mark IIIs: Case 2 (Portable Diesel)

Table A-4 Input for Uncertainty Analysis: Case 3 (Igniters plus Air Return Fan)

Cost Element	Dual Unit ICs (DU)	Sequoyah (SQ)	Watts Bar (WB)	Mark III (M3)
Materials and Equipment				
low	$80,000	$212,000		NA
most likely	$212,000	$262,000		NA
high	$300,000	$350,000		NA
Comments on range (see note below)	range is defined using Duke's data	range is modified for these plants		
Installation				
low	$153,000			
most likely	$180,000			
high	$315,000			
Comments on range	range is defined using Duke's data			
Engineering				
low	$20,000		$45,000	
most likely	$50,000		$75,000	
high	$100,000		$125,000	
Comments on range	range is defined using Duke data		range is modified for this type of plants	
Worker Dose (calculated)				
point estimate	$24,480			
Comments on calculation	The above value is calculated using the expression shown below which is defined in terms of four uncertain parameters (1) Installation cost, (2) dose rate, (3) hourly labor rate, and (4) % exposure			
	$\frac{\text{installation cost}}{\text{hourly rate}} \times \text{dose rate} \times \%\ \text{exposure time} \times \$2000$			
	Installation cost	Range defined above	hourly labor rate	
			low	$30
			most likely	$40
			high	$50
	dose rate (rem)		% of exposure time	
	low	0 002	low	20%
	most likely	0 005	most likely	40%
	high	0 01	high	60%
Emergency Procedures				
low	$20,000		$30,000	
most likely	$30,000		$50,000	
high	$42,500		$75,000	
Comments on range	range is modified for this type of plants		range is defined using SAMAs	
Licensing Costs				
low	$3,750		$5,000	
most likely	$6,250		$10,000	
high	$8,750		$15,000	
Comments on range	range is modified for this type of plants		range is defined using staff experience in perfoming 50.59	
Industry Operation				
low	$20,000			
most likely	$50,000			
high	$100,000			
Comments on range	range is defined using Duke's data and Dominion SAMA			
NRC Implementation				
low	$14,450			
most likely	$17,000			
high	$29,750			
Comments on range	range is defined based on 50 44 rulemaking			
NRC Operation				
low	$1,700			
most likely	$2,000			
high	$3,500			
Comments on range	range reflects uncertainty in the cost for increase in inspection accounting for 40 years of remaining life			

Note: the uncertainty in the value of the parameters of the cost model was characterized using a triangular distribution with three points – low, most likely value and high

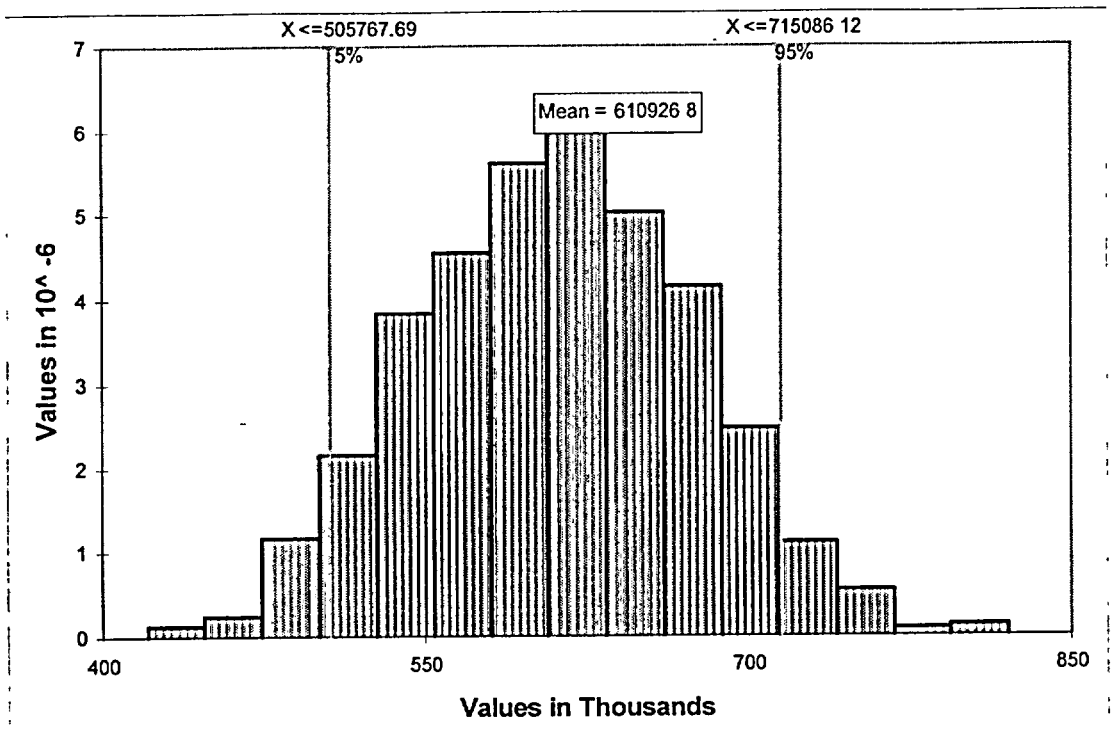

Figure A-9 Distribution for Total Cost for McGuire, Catawba, and Cook (per unit): Case 3 (Igniters and ARF)

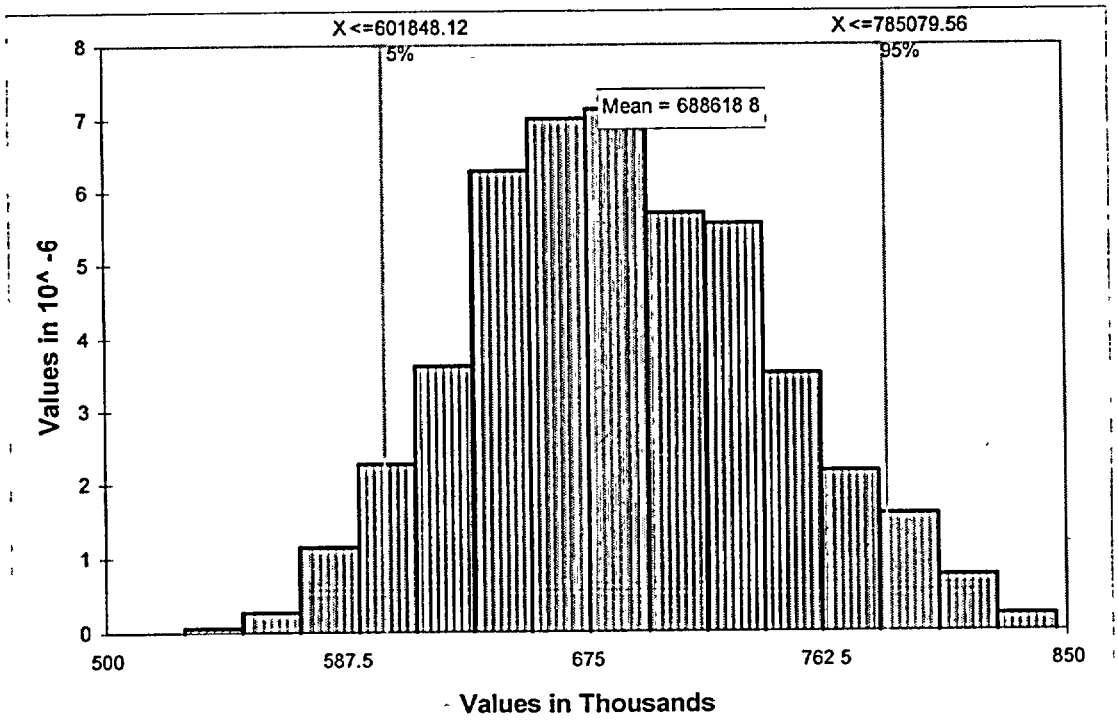

Figure A-10 (Distribution for Total Cost for Sequoyah (per unit): Case 3 (Igniters and ARF)

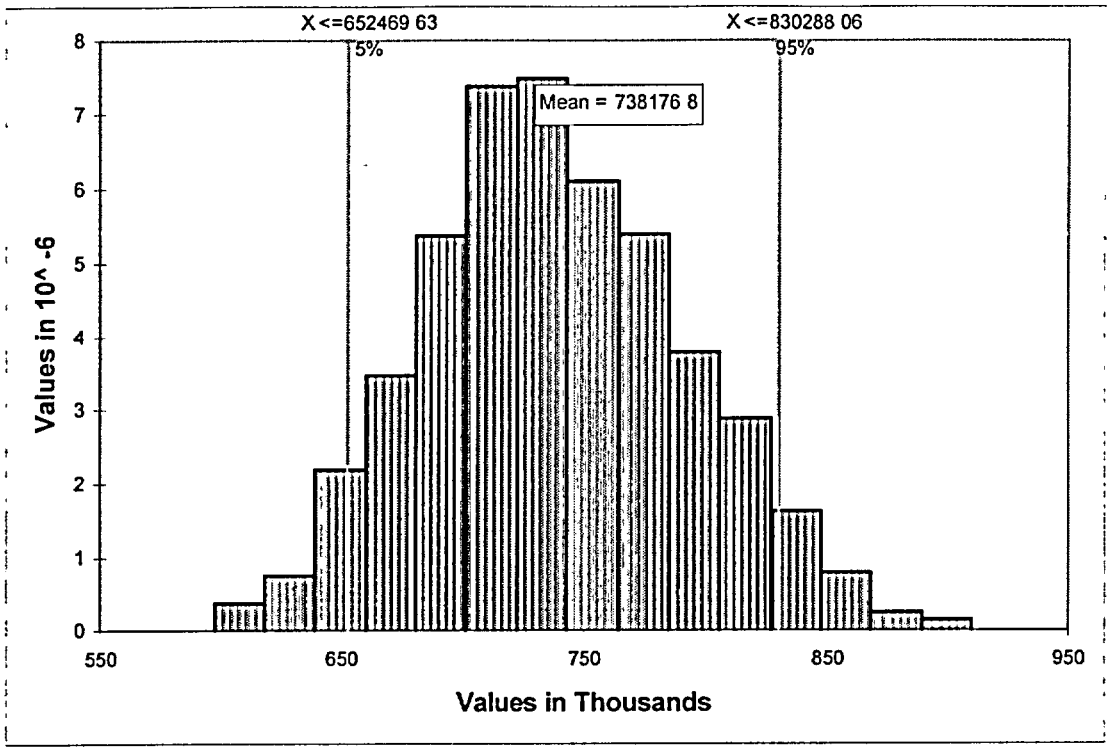

Figure A-11 Distribution for Total Cost for Watts Bar: Case 3 (Igniters and ARF)

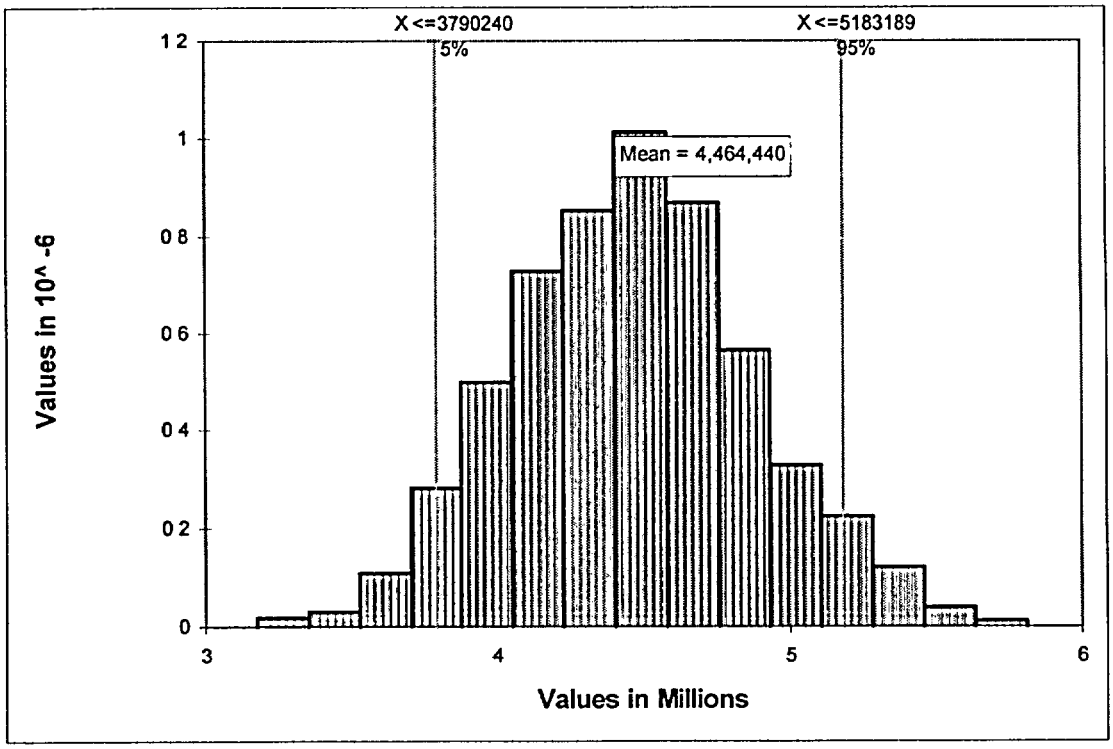

Figure A-12 Distribution for Total Cost for the Industry: Base Case (Pre-Staged)

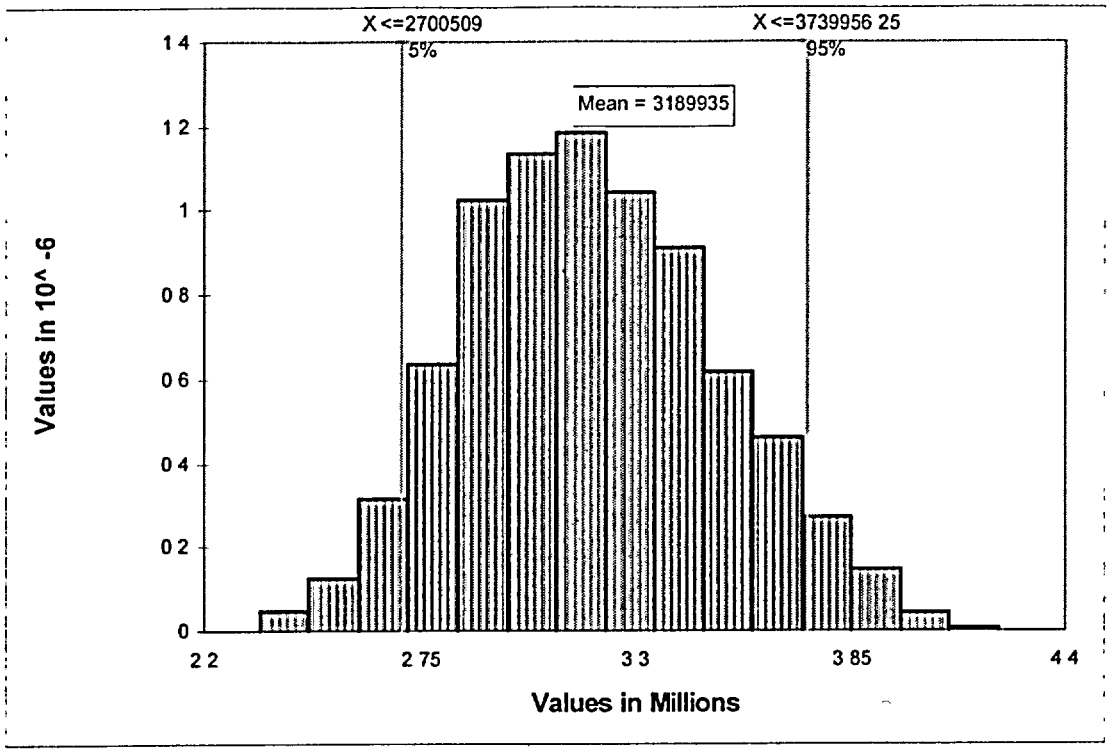

Figure A-13 Distribution for Industry/Total Cost for the Industry: Case 2 (Portable Diesel)

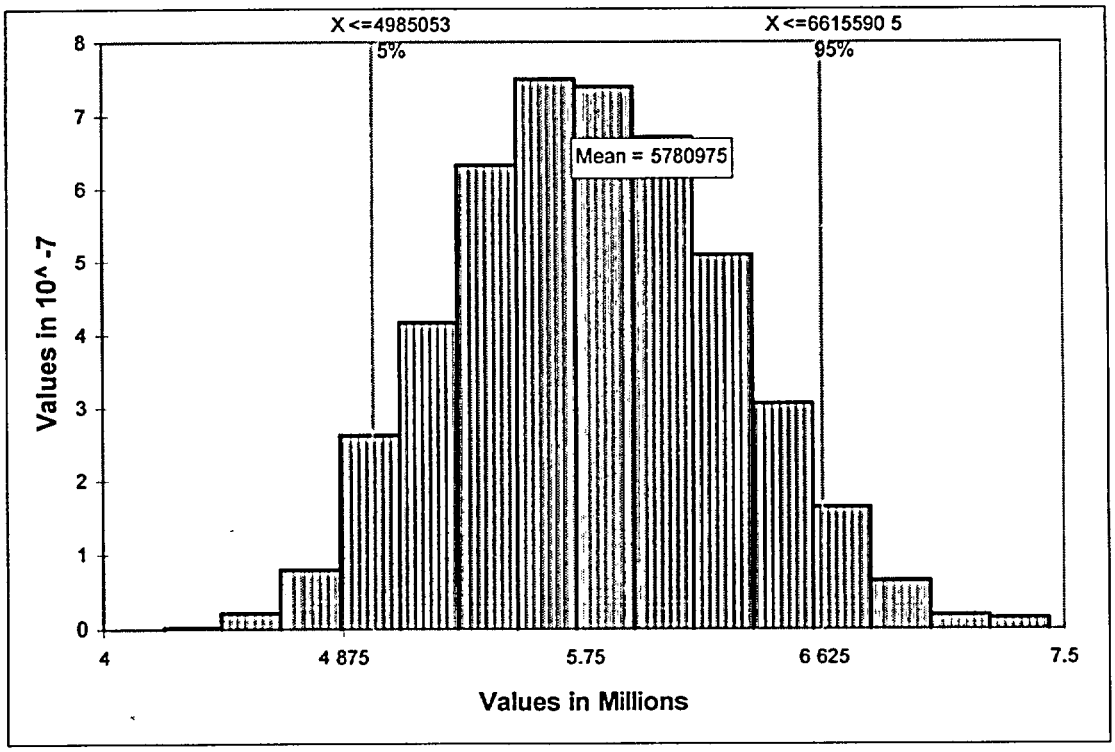

Figure A-14 Distribution for IC Industry/Total Cost for the Industry: Case 3 (Igniters and ARF)

Hydrogen Control Calculations for the Sequoyah Plant
Reference and Uncertainty Calculations

Draft Letter Report [Revision No. 3]
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Task No. 1: PO# 28839

Hydrogen Control Calculations for the Sequoyah Plant
Reference and Uncertainty Calculations

1 Introduction

The Sequoyah containment is equipped with a system of igniters designed to ensure controlled burning of hydrogen in the unlikely event that excessive quantities of hydrogen are generated and released to the containment during a postulated degraded core accident. The igniters operate as hermetically sealed thermal igniters. Power is supplied directly to the igniter at 120-V ac.

During station blackout accident scenarios, offsite and onsite power to the igniters will be interrupted; therefore the igniters will not be available as a hydrogen control system. The series of calculations discussed in this report addresses hydrogen distribution and burn (deflagration) behavior in the Sequoyah containment should onsite power be provided to igniters and/or air return fans during a station blackout accident. The calculations have been performed by de-coupling the MELCOR reactor cooling system (RCS) models from the containment model, thereby analyzing the containment response as a standalone problem. This de-coupling procedure has the advantage of unburdening the containment analysis by the time consuming calculations performed in the CORE package of an otherwise combined RCS and containment response calculation. Because feedback from the containment system to the RCS is weak, this type of de-coupling can be accomplished without significantly affecting the source terms (water, steam, and hydrogen) to the containment or the subsequent containment response.[1] Within MELCOR's control volume and flow path packages, I/O features are provided to allow the type of de-coupling discussed here.

The specific accident event selected for analysis is a short-term station blackout accident with pump seal leakage (250 gpm leakage), STSBO-L.[2] From a series of MELCOR source-term uncertainties calculations, reference and selected uncertainty runs have been chosen for use in the containment analysis study. The selection criteria for the reference and uncertainty source-terms (water, steam, and hydrogen injections to the containment) used in this study are discussed later. Issues of hydrogen control scenarios explored in the report are:

- Delayed deflagration without power to either igniters or fans
- Controlled burning with power to igniters
- Controlled burning with power to igniters and fans.

[1] A fully coupled calculation is required to account for the affect that small releases of radioactive nuclides have on the containment response. The analysis of these types of second order effects will has been addressed in separate calculations discussed in Appendix A.
[2] See "An Uncertainty Analysis of the Hydrogen Source Term for a Station Blackout Accident in Sequoyah Using MELCOR 1.8.5", Sandia National Laboratories Letter Report, 30 September, 2002.

The discussions in the following sections focus on hydrogen control conditions with uncertainties investigated for burn parameters and source terms. In a previous report[3] other uncertainties associated with code input were discussed: ice bed nodalization and bypass leakage flows. The source term input for the previous report are superseded by the source terms referenced in this report; however, the conclusions of the earlier study regarding nodalization and bypass remain unchanged: 1) additional vertical segmentation of the ice bed produces no significant change in ice-bed hydrogen concentrations; and, 2) changes in bypass flow area (0.03 – 0.29 m2) and elevation (10 – 20 m) produce no significant change in the containment hydrogen concentrations. Additionally, in earlier addendums to the previous report, fully-coupled RCS/containment MELCOR calculations with power to igniters were conducted to investigate late time (post vessel failure) hydrogen control behavior with core/concrete interactions (CCI). These calculations, also conducted with earlier MELCOR source terms, indicated that oxygen depletion prior to vessel failure substantially reduces the risk of late time overpressurization due to deflagrations or potential detonations. This conclusion is not expected to change with the more recent source terms generated by the current MELCOR Sequoyah plant models. Therefore, these calculations are not repeated for this report. The results of the earlier, fully-coupled RCS/containment calculations are however included as Appendix A. Finally, the possibility of diffusion flames at the top of the ice condenser was considered in the preparation of this report, with attempts to include this type of burn scenario in the study. However, the analysis (diffusion flame without DCH) could not be completed without code modification, and therefore was excluded from the study.

In section 2, the MELCOR containment model is described along with the various hydrogen source terms obtained from MELCOR station blackout calculations. The reference and representative "uncertainty" source term inputs are also discussed in section 2. Hydrogen control in the containment is discussed in section 3 for both reference and uncertainty source terms. Section 4 presents results of an uncertainty/sensitivity analysis for burn parameters (Monte Carlo uncertainty study for the standalone containment analysis). Section 5 summarizes the study results.

2 MELCOR Sequoyah Containment Model (s)

Shown in Figure 1 is a drawing of the Sequoyah containment indicating boundaries of three major containment regions: lower containment, ice-condenser, and upper containment. The ice bed is isolated from the lower and upper containment by lower plenum, intermediate, and upper plenum doors that remain shut during normal operation. During postulated accident events leading to RCS injections of water and steam to the lower containment, these doors can open as a result of the pressure differentials across the doors. Steam flowing into the ice condenser is condensed onto ice baskets holding flakes of ice. The ice bed is therefore a region of low steam concentration, and a probable location for high concentrations of released hydrogen in the case of degraded

[3] Hydrogen Control Calculations for the Sequoyah Plant: Station Blackout Scenario, April 2002, Draft Report.

core accidents. There are no igniters located in the ice bed, and therefore any burns in this region must be initiated as a result of flame propagation.

2.1 Nodalization

Figure 2 is a sketch of a containment model indicating the various sub-compartments that are modeled the MELCOR standalone, containment model referred to here as the 26-cell model. Table 1 lists the compartment descriptions for each cell in the model. The 26-cell containment model is derived directly from a CONTAIN containment model discussed in NUREG 5586 – a copy of the MELCOR standalone containment input files (MELGEN/MELCOR files) for the case with power to igniters is included as Appendix B. One important feature of the model is the nodalization of the ice bed, Figure 3. The ice bed is represented by four azimuthally arranged cells (18-21) that extend from the bottom to top of the ice bed. Vertical density profiles within the ice bed cannot be calculated with this model. However, upper and lower circulation paths within the ice bed are provided to allow circulation resulting from variations in the static heads between cells. The rationale for using single cells to represent vertical portions of the ice bed is driven by a number of reasons, some physically based and others based on practical and model consistency arguments.

From a physical standpoint, it is believed that significant vertical compositional and density differences within the ice bed, during a degrade core accident such as the STSBO-L sequence, is highly unlikely. This belief is based mainly on mixing process generated as the result of 1) the relatively high rates of steam and hydrogen injection into the ice condenser during the scenario, and 2) the likely asymmetrical character of those injections. Additionally, the entrance location for injections is in a region, under stagnant conditions, that is most likely to form a stratified layer (gas mixtures remaining in the ice bed will become heavier as the mixture is cooled and depleted of steam, settling to the lower regions of the ice bed). Injections into this region will most readily disrupt the stratifying layer. To investigate the propensity for circulation and uniform mixing, a coarse vertical/horizontal ice bed nodalization scheme was utilized early in this study. The purpose for using this more detailed nodalization scheme was to show that gross circulations within the ice bed occur during the accident sequence, and that a single, vertical cell model for the ice bed (azimuthally configured cells) is reasonable. Of course, small local or secondary circulation behavior cannot be addressed with such lumped-parameter modeling; however, small regions with variable vertical composition and density variations are considered of minor significance for the purpose of this study which focuses on overpressurization resulting from global deflagrations.

For the practical aspects of ice bed modeling, additional vertical segmentation of the ice bed, especially for cases with fans operating significantly slows the calculations, inhibiting an ability to perform statistical (Monte Carlo) uncertainty/sensitivity studies for burn parameters. From a model consistency standpoint, vertical burn propagation using single, vertical cells in the ice bed represents a consistent treatment for flame propagation correlation and usage. The correlations for flame speeds are derived only for single compartment burns. Propagation of burns in relatively open regions (which may also

have composition and density gradients) using multiple-cells is not validated for a lumped-parameter codes like MELCOR. A single, vertical cell model represents therefore a consistent treatment for flame propagation based on current code correlations.

Within the other regions of the containment (upper and lower containment), the containment model divides into specific confinement regions, generally isolated by well defined flow paths. The vertical segmentation in the upper containment with the 26-cell model allows for the possibility of upper containment stratification of air and hydrogen in the dome. A tendency for some stratification in this regard is noted in calculations without the fans operating. Within the lower containment, additional compartments are modeled to allow simulation of dead-ended regions. These regions can be de-inerted during significant periods due to high concentrations of steam that build-up during the early portion of an accident, prior to hydrogen release.

2.2 Source terms

Hydrogen control calculations for the Sequoyah plant were first reported in an April 2002 draft report. In that report, the source term for the containment was documented by SNL in a report "Hydrogen Source Terms for Station Blackout Accidents in Sequoyah and Grand Gulf Estimated Using MELCOR 1.8.5, dated July 26, 2001. Since the SNL July report an updated set of hydrogen source term calculations have been completed at SNL in a September, 2002 report. The purpose of the more recent calculations (40 runs in all) was to estimate the uncertainty in hydrogen source terms though variations in Core and RCS model input parameters. The calculations were conducted for a STSBO-L sequence using a new 5-Ring model of the Sequoyah core (original calculations made with 3-Ring core model) together with other modifications made to the RCS coolant loops.

Shown in Figures 4 and 5 are the in-vessel hydrogen generation profiles for the 40 MELCOR runs recently completed at SNL. The hydrogen generation ranges from approximately 430 to 600 kg at the time of vessel failure. For the purpose of determining the effect of source term variation on hydrogen control, three representative source term runs were selected for the standalone containment analyses. These runs are summarized in Table 2. The selected runs provide a reasonable range of the high and low hydrogen source terms (run 21 vs. 35) and in addition include the variability of hot leg failure/no failure (run 21 vs. 32).

Hydrogen, water, and steam can enter the lower containment (prior to vessel failure) from primary system leaks (pump seals), valve openings (PORVs, etc.), and coolant line breaks (hot leg and/or surgeline breaks). Shown in Figure 6 are the approximate locations for these sources. The mass rate and integral amount of hydrogen injected into the containment for MELCOR run 21 are shown in Figure 7 and 8 for the pump seals and hot leg break, respectively. For run 21, hydrogen is not released from the PORVs since these injections (both water and steam), as shown in Figure 9, occur prior to the start of hydrogen generation, Figure 10. Since the surgeline does not fail in run 21, there are no hydrogen injections from the surgeline. Water and steam injections from the pump seals and steam injection from the hot leg break are shown in Figures 11 – 13.

Total hydrogen generated in-vessel for run 21, Figure 10, shows that there are essentially two phases to the generation and similarly the injection process. The first phase, responsible for approximately 515 kg or 90% of the total hydrogen release, is from the pump seal leakage over about a 1.5 hour period beginning at 3.5 hours into the accident. When the hot leg of the RCS fails due to creep rupture at ~ 5.4 hours, an additional ~55 kg of hydrogen is released along with a surge of steam which rapidly pressurizes the containment. Following the hot leg rupture, the steam sources to the containment are relatively minor and the containment depressurizes somewhat as it cools before lower head failure occurs at approximately 6.4 hours into the accident.

The uncertainty range for hydrogen source terms is represented by MELCOR runs 21, 32 and 35 as indicated in Table 2. The in-vessel hydrogen generation rate and integral amount for runs 32 and 35 are shown in Figures 14 and 15. These sources can be compared to those in Figure 10 for run 21, representing a case with a high mass rate and cumulative injection. The hydrogen injection rates for run 32 (pump seal) and 35 (pump seal and hot leg) are shown in Figures 16 - 18.

3 Hydrogen Control

Without controlled hydrogen burning there is a risk that hydrogen will accumulate in the containment and possibly ignite at a time when a "global" deflagration will be severe enough to threaten the integrity of the containment. For example, shown in Figure 19 is a case where a global burn is delayed until ignited by hot ejected core material at the time of vessel failure. For the Sequoyah containment, the pressure corresponding to an estimated 10% failure probability is 525 kPa (absolute).[4] The risk of over-pressurizing the containment from a delayed global deflagration is clearly apparent without hydrogen control. However, there are also other concerns. Local pockets of hydrogen having high concentrations could ignite to produce an accelerated flame, deflagration to detonation transition (DDT), or in some cases a detonation directly. In the following analyses we assess the hydrogen distributions within the containment for possible local combustion events. The cases investigated are those having 1) no power to igniters, 2) power to igniters only, and 3) power to igniters and fans (single train). The hydrogen source term calculated in MELCOR run 21, representing a high hydrogen injection scenario, is selected as a "reference case." Source terms for MELCOR runs 32 and 35 are used to indicate the variability in hydrogen behavior as a result of source term uncertainty.

Shown in Figures 20 – 22 are containment pressures calculated for the cases without igniters, with igniters, and with igniters and fans (single train). For the ignition of hydrogen, the combustion and propagation limits listed in Table 3 are used. Locations for the igniters are shown in Table 4. Figures 23 – 25 show the ice-bed hydrogen concentrations for run 21 for the case without igniters, with igniters, and with igniters and fans, respectively. The ice-bed hydrogen concentrations for runs 32 and 35 are presented in Figures 26 – 28 and Figures 29 – 31.

[4] See Table B.4 in NUREG 6247 for ice condenser containment fragility measures.

The upper containment (compartment #24) hydrogen concentrations for the MELCOR runs 21, 32, and 35 are shown in Figures 32, 33, and 34, respectively, for each case with, without igniters and with igniters and fans.

A comparison of hydrogen burn totals by region for the various MELCOR runs (source terms) with igniters and with igniters and fans is presented in Tables 5a, 5b, and 5c. The total hydrogen burn percentage (hydrogen burn / hydrogen injected X 100) for various source terms show minor sensitivity with percentages ranging from 68 to 74 %. Burn percentages by compartment indicate the shift towards more burning in regions with igniters when the fans operate as compared to the cases with power to igniters only. This means that burns in the ice bed and lower plenum due to flame propagation are minimized when the fans are active. For the upper containment, which is an important control region, the distinction between power to igniters and power to both igniters and fans is small.

It is noted in these calculations for various source terms that a substantial amount of hydrogen is consumed in the lower containment (58-68%) even when fans are not activated. There has been speculation that the lower containment will be steam inerted during the injection, or will be depleted of oxygen as a result of expulsion of air from the lower containment during the injection event, thereby limiting lower compartment burning. Additionally, burning in the lower compartment would consume what small amount of oxygen existed and therefore preclude further burning. As indicated in Figure 35, the lower containment is not inerted by steam during a critical burn period between 3.5 and 5 hours. Furthermore, oxygen in the lower compartment is not limited since there are return air flows from 1) the refueling drains and 2) partially open lower plenum doors (dynamic action and leakage). An important source of the return air to the lower compartment is from the refueling drains. This behavior is shown in Figure 36, where the oxygen flow through the refueling drains to the lower containment is shown (negative flows indicate upper containment to lower containment oxygen transfer). The refueling drains remain open during the early portion of the accident (prior to vessel failure) since containment sprays are inactive for the SBO event and lower compartment water level is too low to flood the drains. Later in the accident, the lower containment water will flood the drains, however, by this time a significant amount of in-vessel generated hydrogen will have been burned.

Shown in Tables 6a and 6b are the hydrogen burn amounts by compartment for two cases (based on the reference calculation) where the refueling drains are assumed closed and in addition the lower plenum door leakages are minimized. A comparison of the results from Tables 5a and 6a indicate that the refueling drain flows affect lower compartment burns significantly – changing the amount burned in the lower containment from 229 to 135 kg, and increasing the amount of hydrogen consumed in the ice bed from 111 to 181 kg. The addition of fans, even with the refueling drains closed, returns the compartment burn percentages to approximately the same percentages when the refueling drains are open. An additional reduction in lower compartment burning occurs when both the refueling drains are closed and the lower plenum door leakage is minimized, Table 6b.

However, the amount is not as significant as when closing just the refueling drain pathways. In each sensitivity case reported for drains or leakage, the addition of fans does substantially reduce the amount of burning in the ice bed, returning the majority of the burns to regions where igniters are located (upper plenum, lower and upper compartment).

Although fan operation produces more burning in regions of igniters, which may be viewed as advantageous, fan operation also results in more rapid depletion of ice prior a period of overpressurization caused by late time CCI. Since this occurrence (rapid ice depletion) may result in a somewhat earlier threat to the containment integrity due to overpressurization, the degree of ice melt for various scenarios is reported in Table 7 for comparisons. Fan operation is seen to increase ice depletion by approximate 15% (i.e. an increase from ~ 45 to 65 % depletion). However, source term uncertainty also causes a substantial variation of ~10% depletion (e.g., 38 to 47% depletion). Interestingly, the ice depletion percentage with fans for one case (run 32) is nearly the same as other cases (runs 21 and 35) without fans. Ice depletion variability in terms of depletion percentages may be as important for the source term uncertainties as for the options of power/no power to fans.

4 Burn Uncertainty/Sensitivity Analysis

The burn parameter uncertainty/sensitivity analysis is performed for the "reference" containment calculation with power to the igniters only. The methodology used for the uncertainty analysis/sensitivity analysis is based on a Monte Carlo (direct statistical method) using subjective probability density functions to describe the burn parameter uncertainties. The method is described in some detail by the international Uncertainty Methods Study Group (labeled the GRS method).[5]

Table 8 gives the deflagration parameters ranges selected for the analysis – the default parameters (see Table 3) are also indicated within the parenthesizes. It was assumed that the subjective probability function profiles for the parameter distributions are uniform. The output indicator of interest for the study is the maximum hydrogen concentration during or at the end of each significant phase of the hydrogen injection event. For this case (MELCOR run 21) the phases are 1) the period of significant pump seal release (3.5 – 5 hours) and at the time just before vessel failure (~ 6.4 hours). The maximum hydrogen concentrations for each time period obtained using the reference case parameters are shown in Table 9. Shown in Table 10 are the uncertainty intervals, represented as the 95% probable and 95% confidence level, for each time interval. To obtain these results, 100 calculations were run using random vector inputs for the deflagration parameters (sampling from a uniform probability distribution function). The largest uncertainty range in hydrogen concentration variation (~ 5%) is for the ice bed, with a maximum concentration of 14.7% indicated.

[5] "Report on the Uncertainty Methods Study," NEA/CSNI/R(97)35/Volume 1, June, 1998.

For the sensitivity analysis, Spearman rank coefficients were determined for each burn parameter based on the results of the uncertainty study that included 100 output vectors. The Spearman rank coefficients can vary from -1 to 1. A negative coefficient indicates that an increase in the burn parameter value will result in a decrease in the output variable. Conversely, a positive coefficient indicates that an increase in the burn parameter results in an increase in the output variable. A 95% confidence level that there exists a correlation requires that the absolute value for the rank should be greater than approximately 0.2 (100 random trials). Tables 11 and 12 present the rank coefficients for each injection or analysis period. Larger absolute values of the rank coefficients indicate a stronger correlation. For example, an increase in the hydrogen concentration limit for ignition results in an increase in the maximum hydrogen concentration in the ice bed during the 3.5 - 5 hour period. The most obvious correlations are for 1) the hydrogen concentration limit for ignition (all regions), 2) the maximum steam concentration for ignition (ice bed and upper containment), and 3) the hydrogen concentration limit for downward propagation (ice bed). Phenomena with no apparent correlation between hydrogen concentration uncertainties and burn parameter are 1) hydrogen concentration for upward propagation (lower compartment and ice bed) and 2) hydrogen concentration for horizontal propagation (lower compartment and ice bed).

5 Summary

A short-term station blackout with pump seal leakage scenario (STSBO-L) has been analyzed using the MELCOR code to determine potentially severe containment loads that may be produced with and without active hydrogen control. The analysis, conducted for the period of time up to and including vessel failure, showed that active hydrogen control may be necessary to avoid challenges to the containment. The standalone containment analysis used a detailed description of the containment (26-cell model) and source terms for water, steam, and hydrogen to the containment. The source terms were generated by separate MELCOR code calculations reported elsewhere. Three scenarios were selected from a MELCOR uncertainty analysis of hydrogen sources terms to obtain a representative range of high and low hydrogen injections (570 to 430 kg) to the containment.

Hydrogen control through the supply of power to igniters was studied, as well as the case for power to igniters and fans (single train). For scenarios with power to igniters only, it was shown that 1) global hydrogen concentrations (especially in the upper containment) can be safely reduced and the potential for a delayed global burn avoided, and 2) local hydrogen build-up in the ice bed can be mainly eliminated. The range of source term uncertainties investigated indicated only minor variations in hydrogen concentrations in the containment with hydrogen control active (power to igniters or to igniter and fans) or in the compartment burn percentages (i.e., containment burn profiles). Fan operation, by mixing the gases in the containment, is shown to reduce somewhat the local build-up of hydrogen, aids in the prevention of steam inerting, and helps to supply oxygen to regions with high burn rates (e.g. the lower containment. In general, the fans enable more burning in regions that have igniters in place (upper plenum and lower containment).

The use of fans results in less dependency on flame propagation into regions like the ice bed. Although the fans help direct most burns to igniter locations, the total amount of hydrogen consumed (at time of vessel failure) is not substantially affected by having fans powered. Additionally with igniters powered, the global hydrogen concentration in the large upper containment region is essentially unchanged with and without fans on. Burns in the lower containment regions are observed to be responsible for the majority of hydrogen depletion even without fans. Such burn behavior is not substantially varied even if fans are powered. Circulation pathways represented by the refueling drains distribute a significant amount of oxygen to the lower compartment even without fan operation. This circulation enables a substantial amount of lower compartment burning to occur.

An uncertainty/sensitivity analysis (direct statistical analysis) of hydrogen burn parameters (e.g., ignition and propagation limits) was completed for a reference scenario (high hydrogen source term) with power to igniters only. Hydrogen concentration uncertainty ranges for the lower containment, ice bed and upper containment were determined for the period of substantial hydrogen injection and the time just prior to vessel failure. The largest uncertainty range (~5% variation) occurred for the ice bed both during the pump seal injection period (~ 9.5 to 14.7%) and later at the ~ time of vessel failure (3.5 – 7.9%). The sensitivity analysis indicated strong correlations between the uncertainty ranges and some parameters for the ice bed (hydrogen concentration limit for ignition and downward propagation, and maximum steam concentration limit for ignition). There were only weak or no correlation for burn parameters including upward and horizontal flame propagation limits.

Table 1. Reference MELCOR containment models for the Sequoyah plant.	
CVH Nos.*	**Location**
26-cell model	
1	Cavity
2-5	Steam Gen. Doghouses
6	Upper Reactor Space
7	Pressurizer Doghouse
8-10	Lower Containment (Inside Crane Wall)
11-13	Lower Annulus (Between Crane Wall and Shell)
14-17	Lower Plenum
18-21	Ice bed
22-23	Upper Plenum
24-25	Upper Dome
26	Lower Dome & Operating Floor

* note the CVH package of MELCOR does not require that compartments (cells) be sequenced in any order.

Table 2. Selected MELCOR Sequoyah Sensitivity Runs					
Run #	Primary System Failure Times (Hours)		Hydrogen Cumulative Mass (Kg)		
	Vessel	Hot Leg	Generated in Core*	Core to Containment	
				Hot Leg	Pump Seals
21	6.37	5.57**	570	55.6	515.2
32	6.3	----	510	----	508.9
35	7.57	6.38	434.5	13.9	420.2
Rev 1 Rpt***	5.45	3.99	476	170	305

* At time of vessel failure
** (triple loop, single loop not failed)
*** "Hydrogen Control Calculation for the Sequoyah Plant: Station Blackout Scenario," April 2002 draft report.

Table 3. Ignition and propagation limits for deflagrations.			
Limits	**X (H2)***	**X (O2)**	**X (steam)**
Ignition	>= 0.05	>= 0.05	<= 0.55
Upward propagation	>= 0.041	>= 0.05	<= 0.55
Horizontal propagation	>= 0.06	>= 0.05	<= 0.55
Downward propagation	>= 0.09	>= 0.05	<= 0.55

Table 4. Igniter locations used in the analysis of the Sequoyah plant.	
Location	**Igniters**
Cavity	No
Steam Gen. Doghouses	Yes
Upper Reactor Space	Yes
Pressurizer Doghouse	Yes
Lower Containment (Inside Crane Wall)	Yes
Lower Annulus (Between Crane Wall and Shell)	Yes
Lower Plenum	No
Ice bed	No
Upper Plenum	Yes
Upper Dome	Yes
Lower Dome & Operating Floor	Yes

Table 5a. Hydrogen consumed in containment for period up to and including vessel breach (26-cell containment model), MELCOR run 21.*		
Location	Hydrogen consumed (kg)	
	Igniters only	Igniters and fans
Lower containment	229 (58.2)**	255.5 (61.4)
Ice condenser	159 (40.4)	105 (25.4)
Ice bed	111.4 (28.3)	25.9 (6.2)
Upper plenum	18.2 (4.6)	76.5 (18.4)
Lower plenum	29.4 (7.5)	2.7 (0.6)
Upper containment	5.6 (1.4)	55.4 (13.3)
Total	393.6	416

* Total hydrogen released to containment up to and including vessel breach is ~ 570 kg.
** Percentage of burned

Table 5b. Hydrogen consumed in containment for period up to and including vessel breach (26-cell containment model), MELCOR run 32.*		
Location	Hydrogen consumed (kg)	
	Igniters only	Igniters and fans
Lower containment	254.4 (66.9)**	227 (60.5)
Ice condenser	126 (33.1)	102.8 (27.5)
Ice bed	96.8 (25.4)	18.6 (5.0)
Upper plenum	13.16 (3.5)	82.4 (22.0)
Lower plenum	16.0 (4.2)	1.8 (0.5)
Upper containment	0.0 (0.0)	45.4 (12.1)
Total	380.4	375.2

* Total hydrogen released to containment up to and including vessel breach is ~ 508kg.
** Percentage of burned

Table 5c. Hydrogen consumed in containment for period up to and including vessel breach (26-cell containment model), MELCOR run 35.*		
Location	Hydrogen consumed (kg)	
	Igniters only	Igniters and fans
Lower containment	163 (55.6)**	151 (49.1)
Ice condenser	127.3 (43.4)	97.5 (31.7)
Ice bed	93.8 (32.0)	20.5 (6.7)
Upper plenum	19.0 (6.5)	75.2 (24.5)
Lower plenum	14.5 (4.9)	1.8 (0.6)
Upper containment	2.74 (0.9)	59 (19.2)
Total	293	307.6

* Total hydrogen released to containment up to and including vessel breach is ~ 434kg
** Percentage of burned

Table 6a. Hydrogen consumed in containment for period up to and including vessel breach (26-cell containment model) for MELCOR run 21, with no circulation through refueling drains.		
Location	Hydrogen consumed (kg)	
	Igniters only	Igniters and fans
Lower containment	135 (35.4)**	255.4 (60.9)
Ice condenser	238 (62.5)	104 (24.8)
Ice bed	181.5 (13.5)	20.5 (4.9)
Upper plenum	13.5 (3.5)	81.5 (19.4)
Lower plenum	43 (11.3)	2.0 (0.5)
Upper containment	7.9 (2.1)	60.0 (14.3)
Total	380.9	419.4

* Total hydrogen released to containment up to and including vessel breach is ~ 570 kg.
** Percentage of burned

Table 6b. Hydrogen consumed in containment for period up to and including vessel breach (26-cell containment model) for MELCOR run 21, with no circulation through refueling drains and no lower plenum door leakage.		
Location	Hydrogen consumed (kg)	
	Igniters only	Igniters and fans
Lower containment	119 (28.8)**	268.0 (63.5)
Ice condenser	283.2 (68.4)	102.8 (24.2)
Ice bed	224 (54.1)	4.8 (1.1)
Upper plenum	29.2 (7.1)	97.0 (23.0)
Lower plenum	30.0 (7.2)	0.5 (0.1)
Upper containment	11.7 (2.8)	51.9 (12.3)
Total	413.9	422.2

* Total hydrogen released to containment up to and including vessel breach is ~ 570 kg.
** Percentage of burned

Table 7. Ice melt percentage at time of vessel failure		
Source Term*	Ice melt %	
	Igniters only	Igniters with fans
Run 21	46.7	64.2
Run 32	37.5	51.2
Run 35	46.1	64.9

* From MELCOR source term uncertainty study, see Table 2.

Table 8. Deflagration parameter uncertainty range		
Parameter	**Uncertainty Range, %**	
	Low	**High**
Hydrogen conc limit for ignition with igniters	5 (5)*	7
Max vapor conc for ignition	45 (55)	65
Hydrogen conc limit for upward propagation	3 (4.1)	5
Hydrogen conc limit for horizontal propagation	5 (6)	7
Hydrogen conc limit for downward propagation	7 (9)	10

* (Default parameter)

Table 9. Maximum hydrogen concentration in Sequoyah containment for the STSBO_L accident event with igniters only (default deflagration parameters)		
Location	**Concentration**	
	3.5 – 5 hrs (pump seals)	**~6.4 hrs (vessel failure)**
Lower cont. (cell #9)	14 %	3.7%
Ice bed (cell #19)	9.5%	6.4%
Upper cont. (cell #24)	3.5%	4.1%

Table 10. Maximum hydrogen concentration uncertainty interval (95%/95%) in Sequoyah containment for the STSBO_L accident event with igniters only		
Location	**Concentration**	
	3.5 – 5 hrs (pump seals)	**~6.4 hrs (vessel failure)**
Lower cont. (cell #9)	14 – 16.6%	3.2 – 4.6%
Ice bed (cell #19)	9.5 – 14.7%	3.5 – 7.9%
Upper cont. (cell #24)	3 – 4.6%	3.8 – 5.2%

Table 11. Spearman rank coefficients for the hydrogen burn parameter study at the 3.5 – 5 hour period (pump seals)			
Parameter	Rank coefficient		
	Cell #9	Cell #19	Cell #24
Hydrogen conc limit for ignition with igniters	0.96	0.66	0.435
Max vapor conc for ignition	-0.11	-0.47	-0.53
Hydrogen conc limit for upward propagation	-0.14	-0.07	0.19
Hydrogen conc limit for horizontal propagation	0.0068	0.03	0.35
Hydrogen conc limit for downward propagation	0.29	0.25	0.24

Table 12. Spearman rank coefficients for the hydrogen burn parameter study near the time of vessel failure (~ 6.4 hours)			
Parameter	Rank coefficient		
	Cell #9	Cell #19	Cell #24
Hydrogen conc limit for ignition with igniters	0.29	0.57	0.41
Max vapor conc for ignition	-0.20	-0.012	-0.1
Hydrogen conc limit for upward propagation	0.204	-0.05	0.17
Hydrogen conc limit for horizontal propagation	0.12	0.14	0.26
Hydrogen conc limit for downward propagation	0.21	0.413	0.10

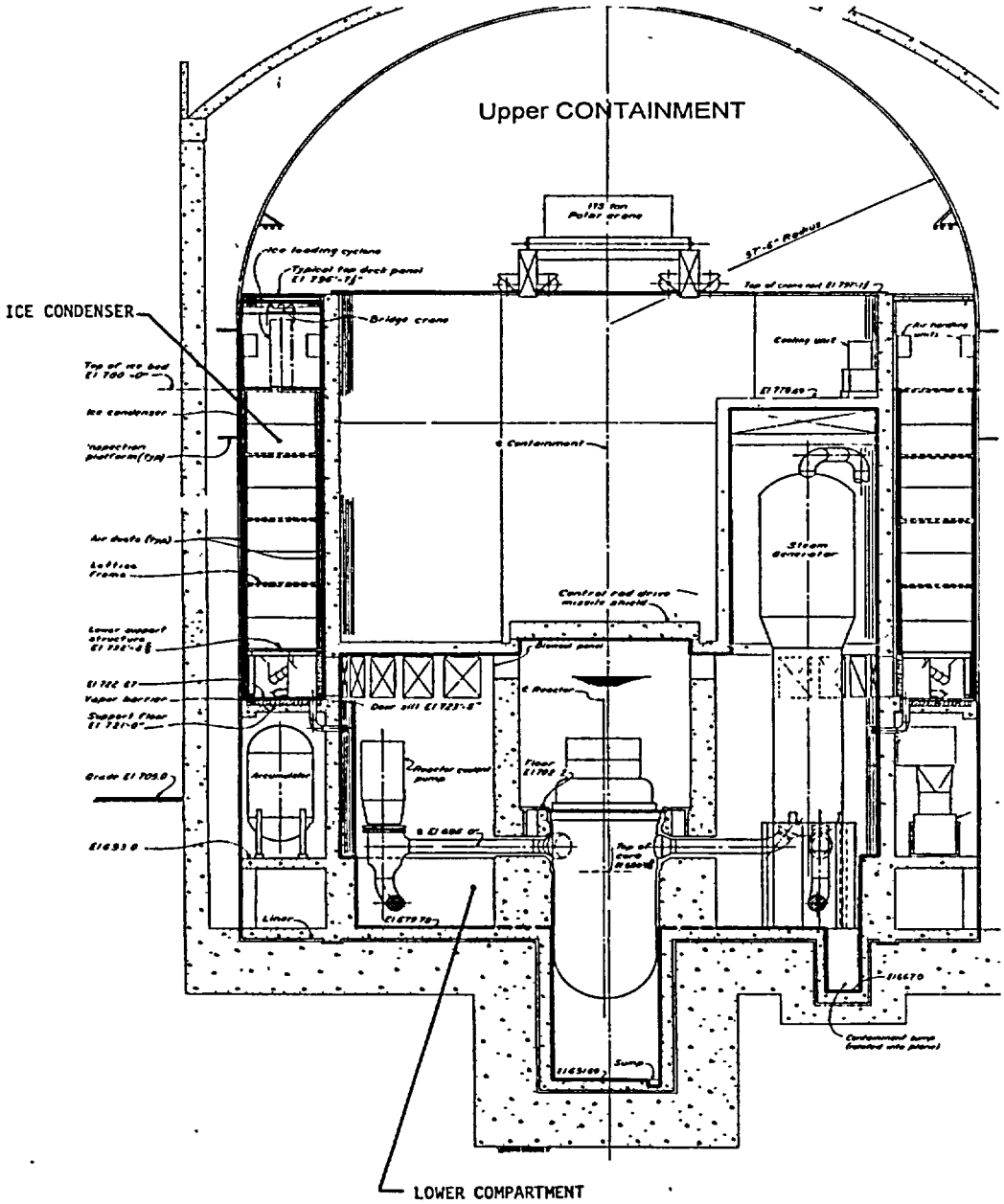

Figure 1 Sequoyah containment drawing [Sequoyah FSAR].

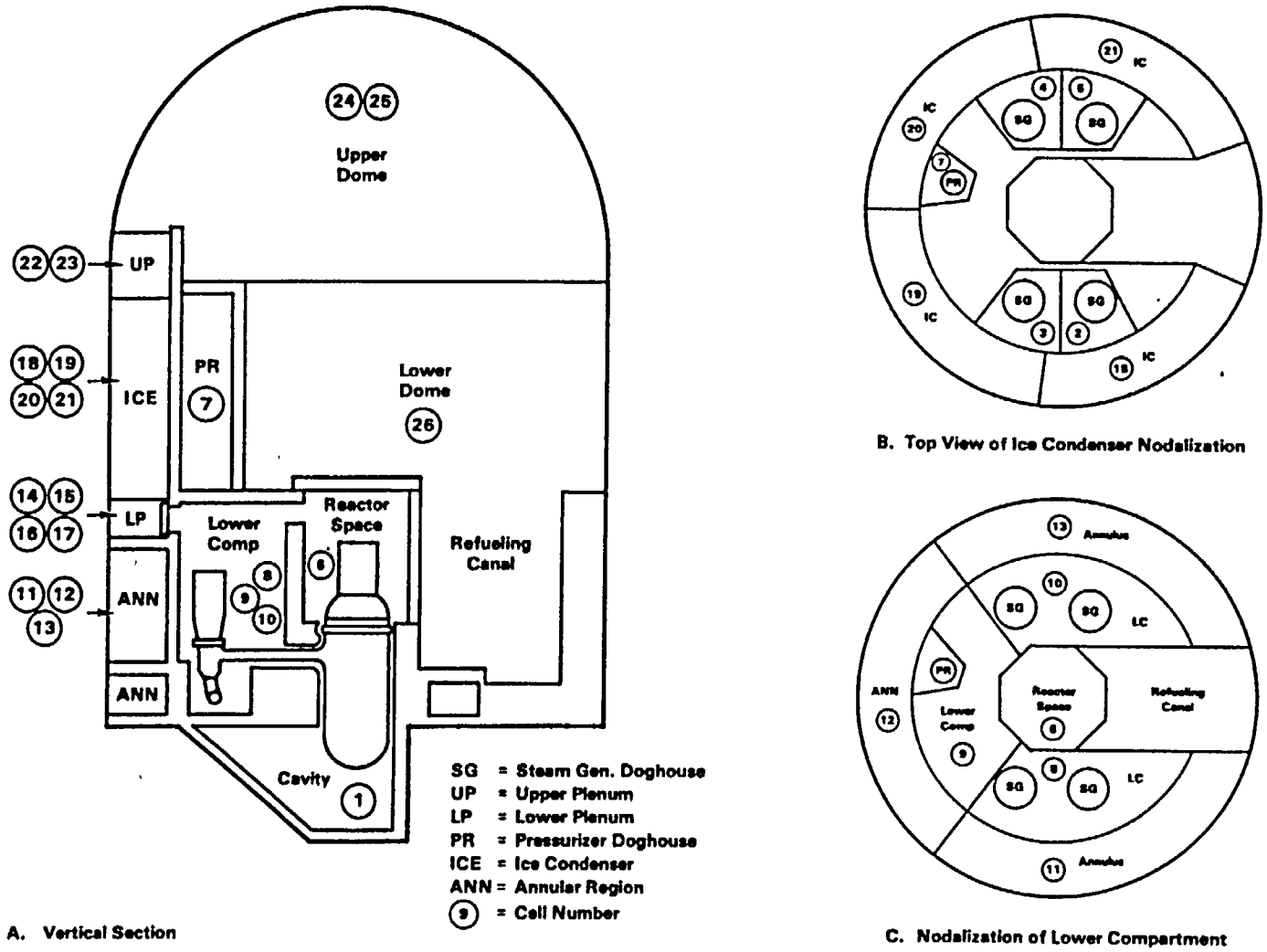

Figure 2 Sketch of Sequoyah containment nodalization for the 26-cell MELCOR containment model.

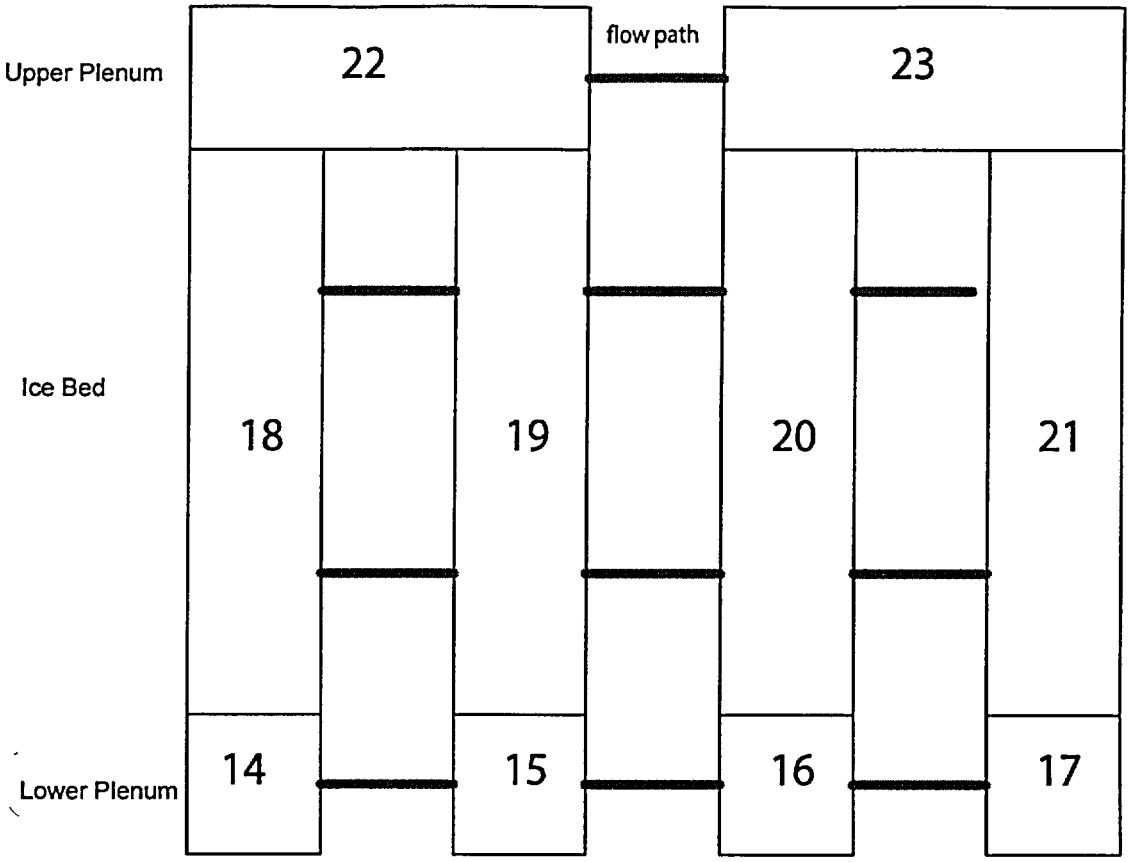

Figure 3 Ice bed nodalization for the 26-cell MELCOR containment model.

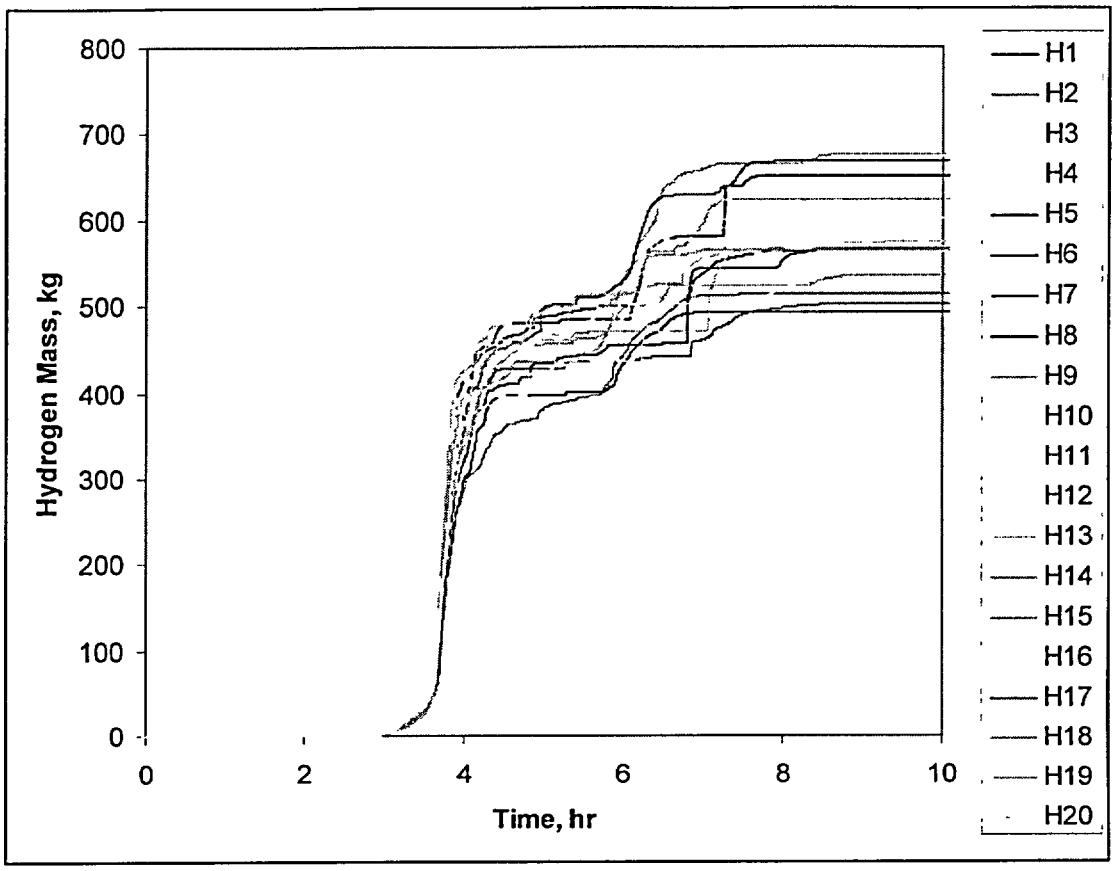

Figure 4 In-vessel hydrogen generation for MELCOR uncertainty runs #1 - #20.

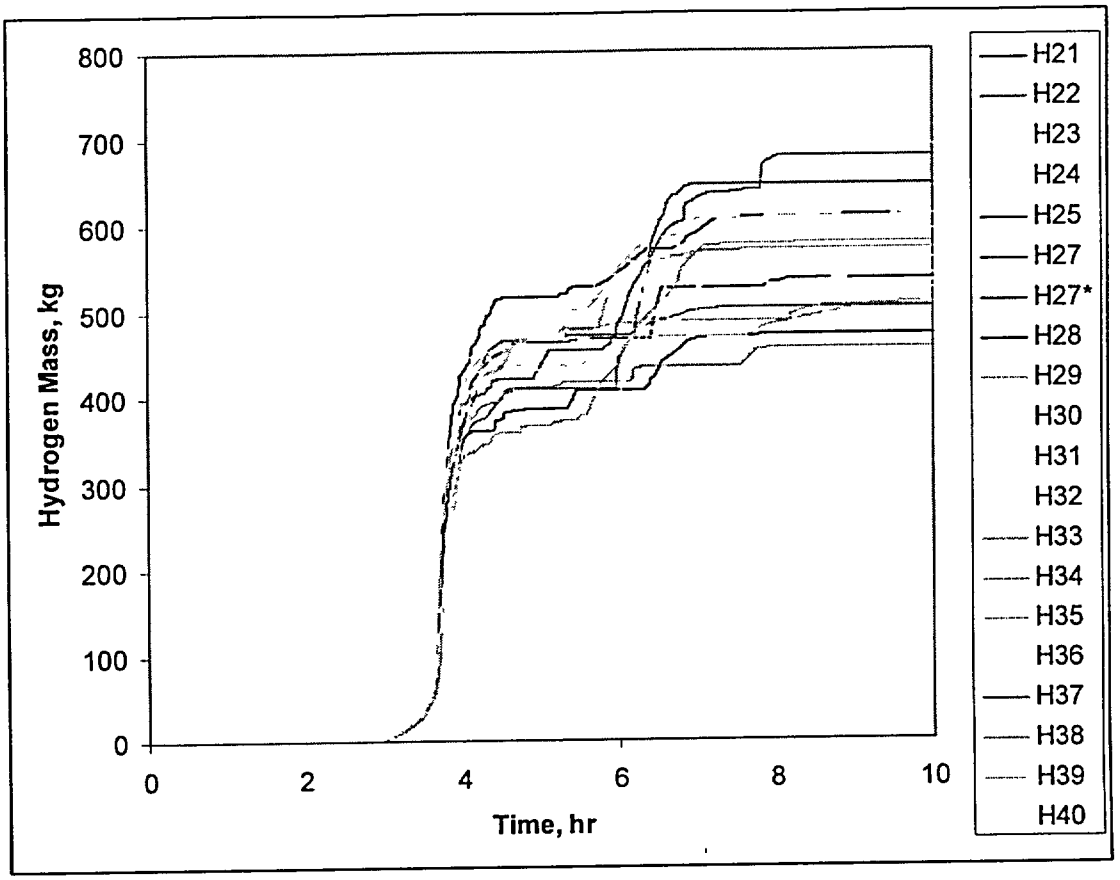

Figure 5 In-vessel hydrogen generation for MELCOR uncertainty runs #21 - #40.

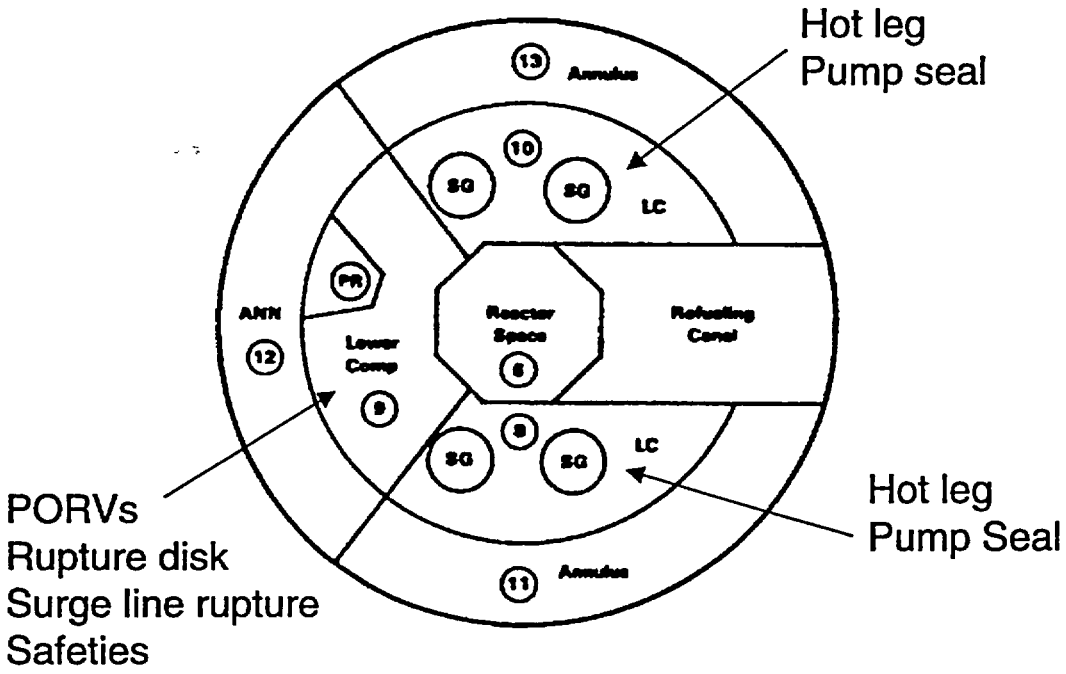

Figure 6 Approximate location for water, steam, and hydrogen injections.

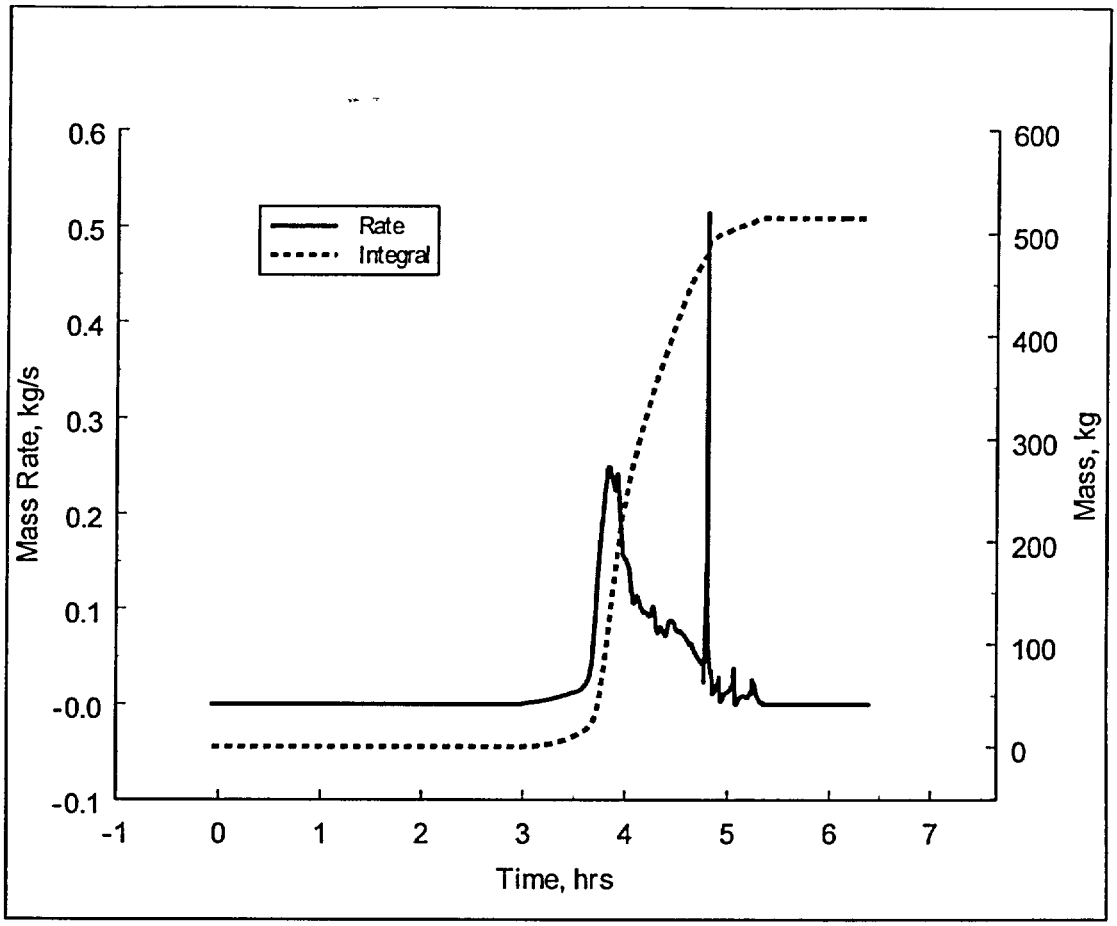

Figure 7 Hydrogen injected through pump seals for MELCOR run 21.

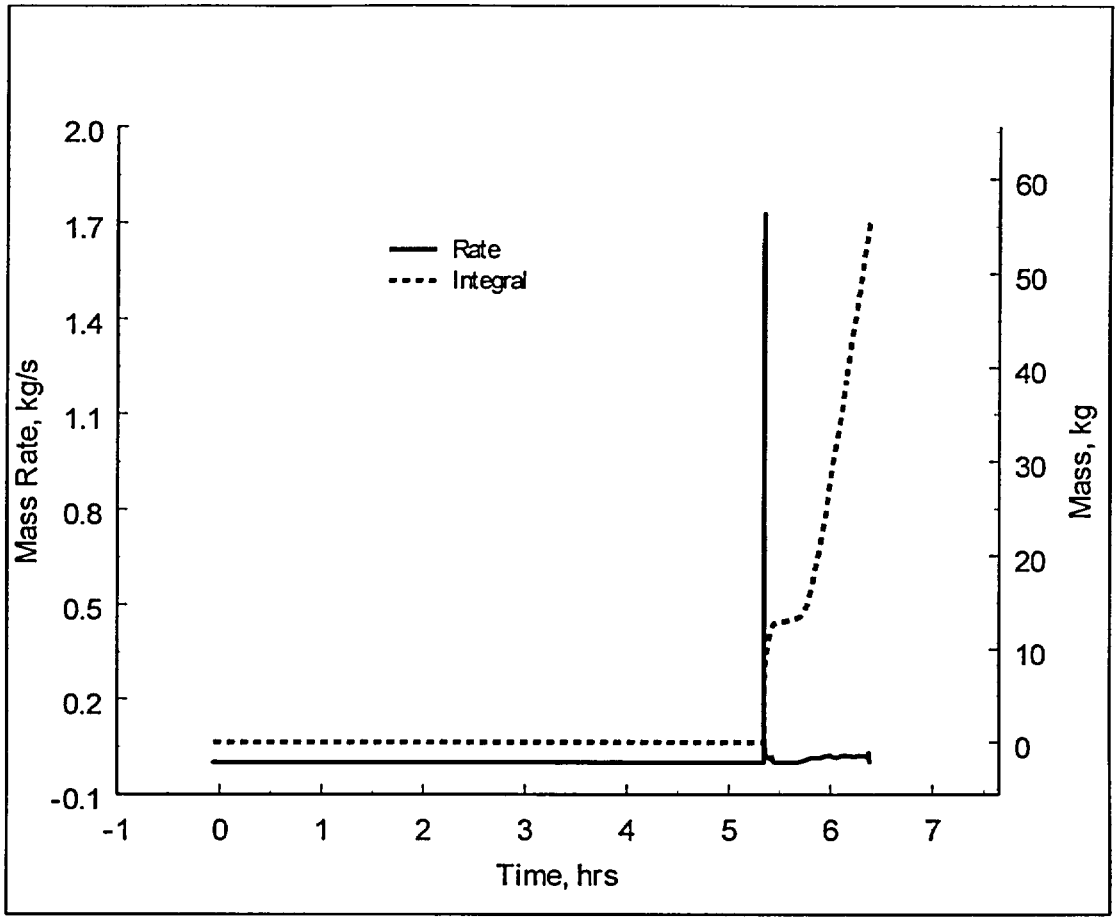

Figure 8 Hydrogen injection through hot leg (triple loop) for MELCOR run 21.

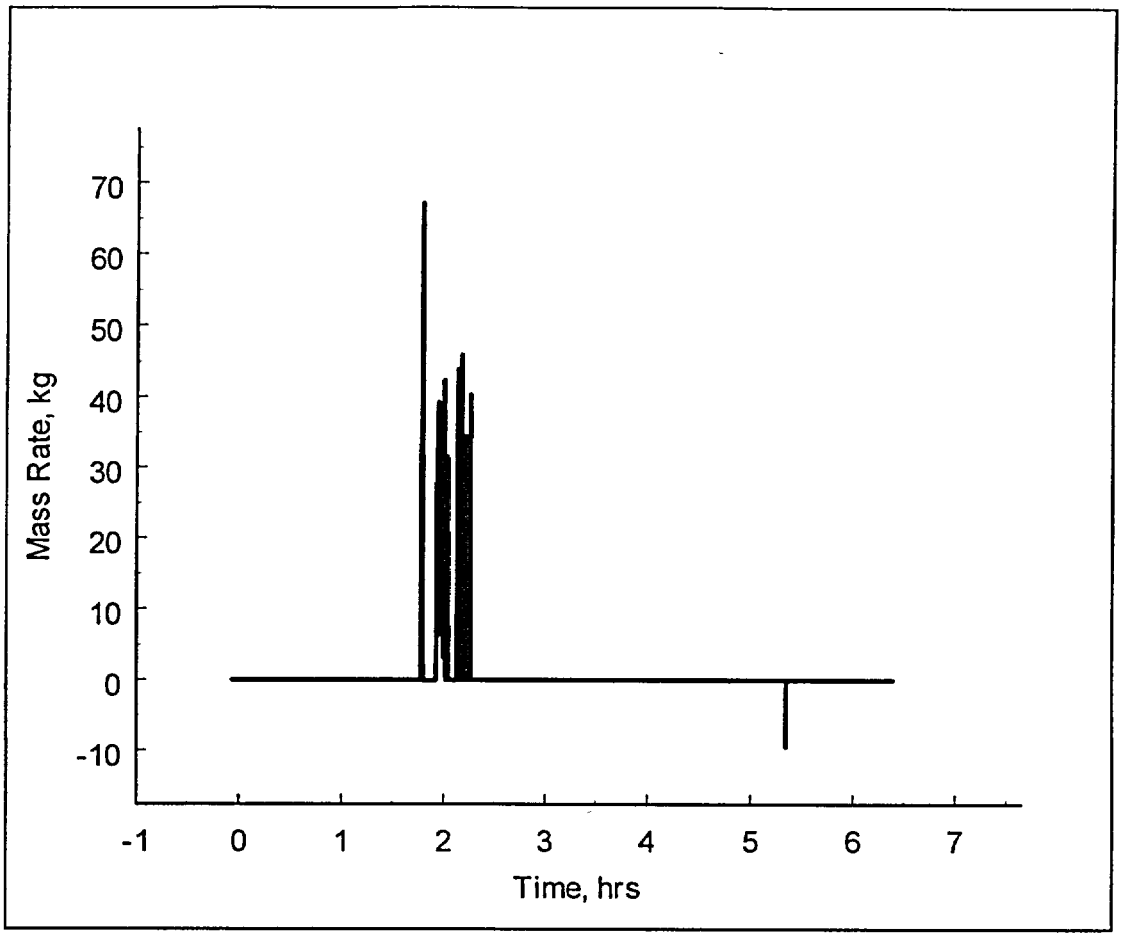

Figure 9 Steam injection from PORVs for MELCOR run 21.

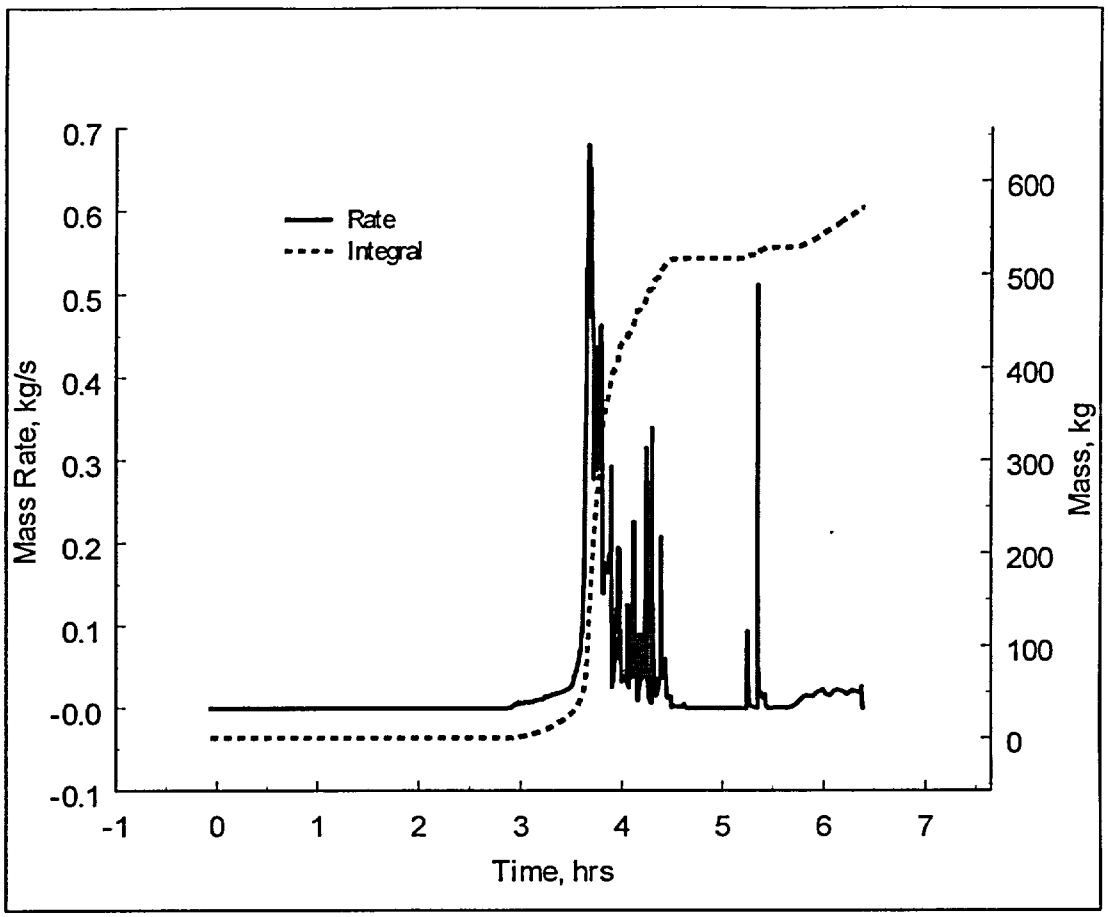

Figure 10 In-vessel hydrogen generation for MELCOR run 21.

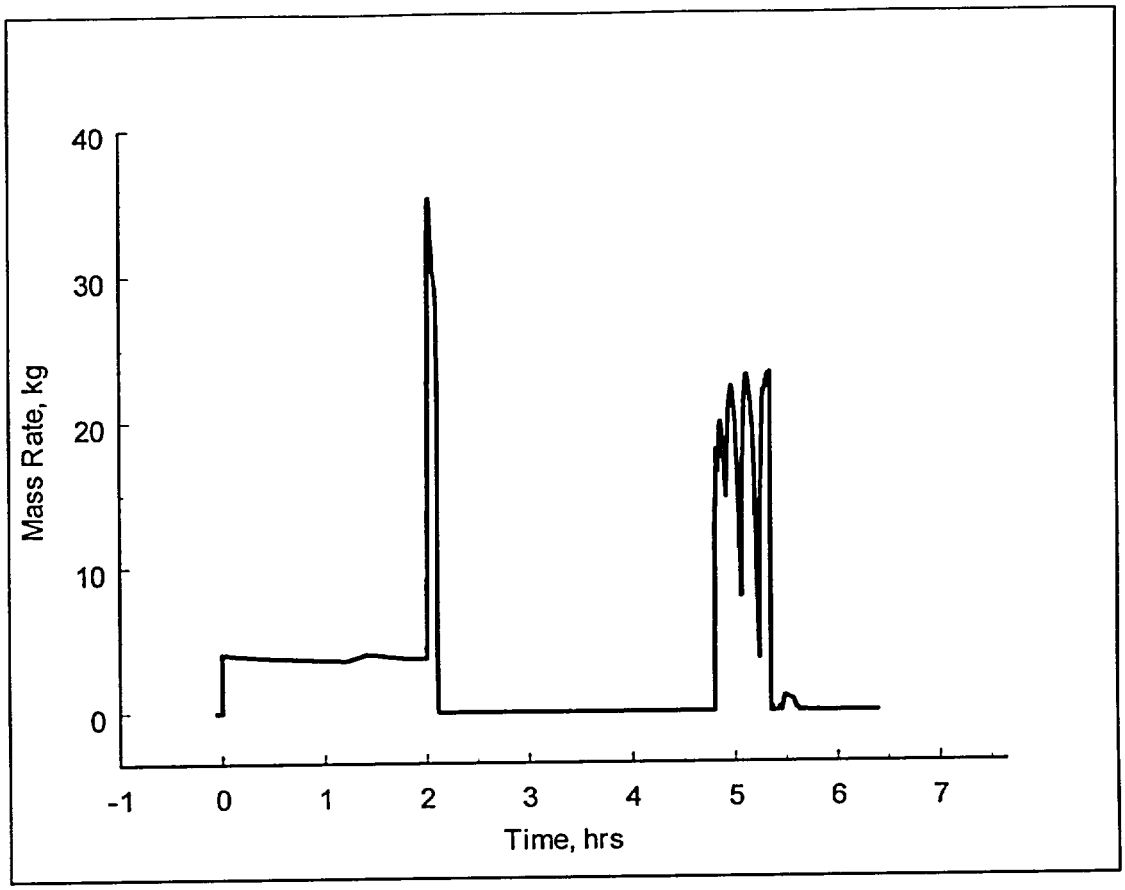

Figure 11 Water injection from pump seals for MELCOR run 21.

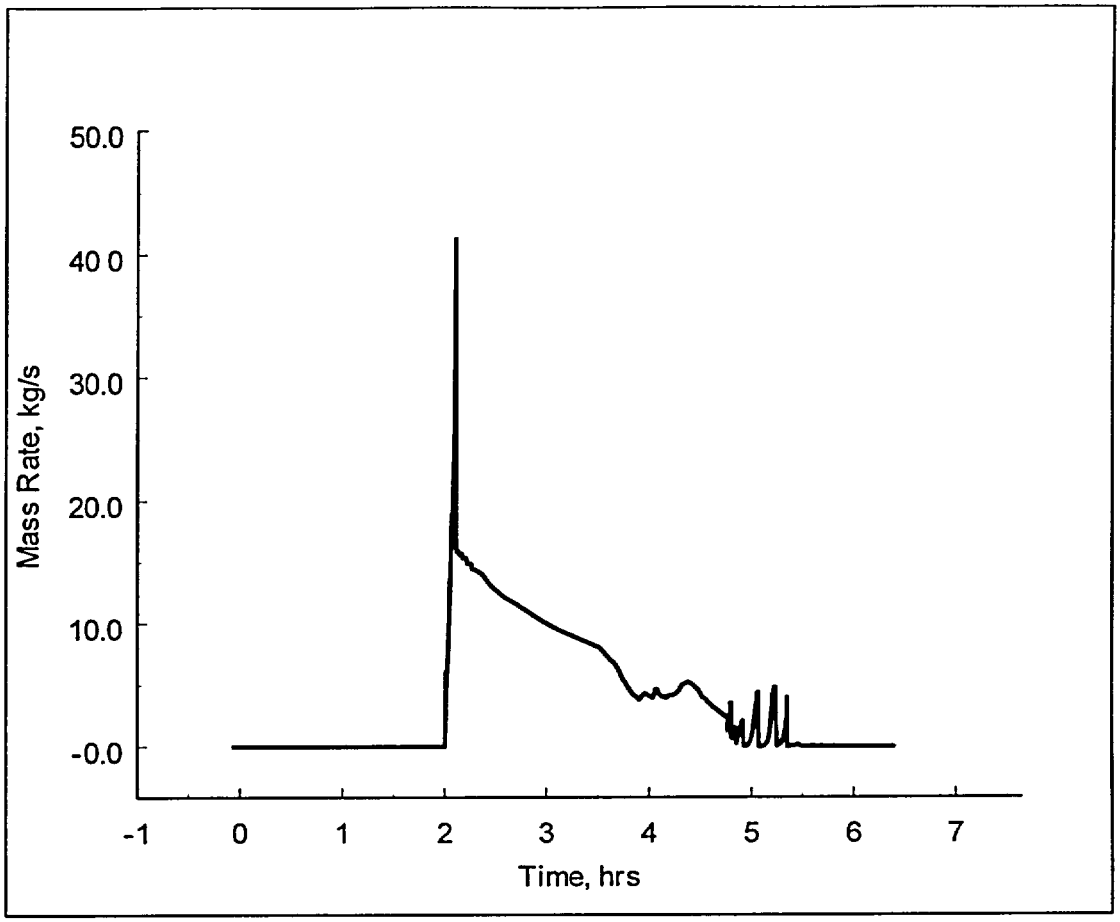

Figure 12. Steam injection from pump seals for MELCOR run 21.

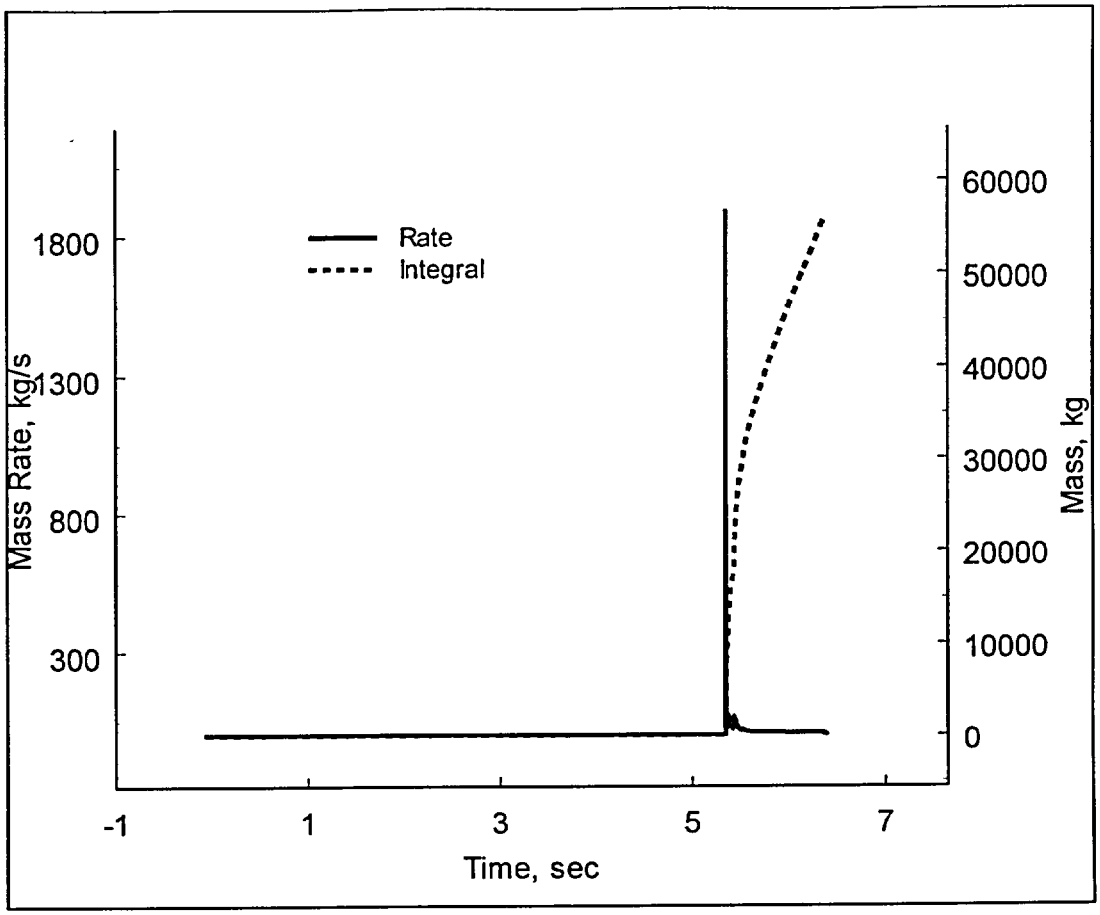

Figure 13 Steam injection from hot leg break for MELCOR run 21 (no liquid water injection).

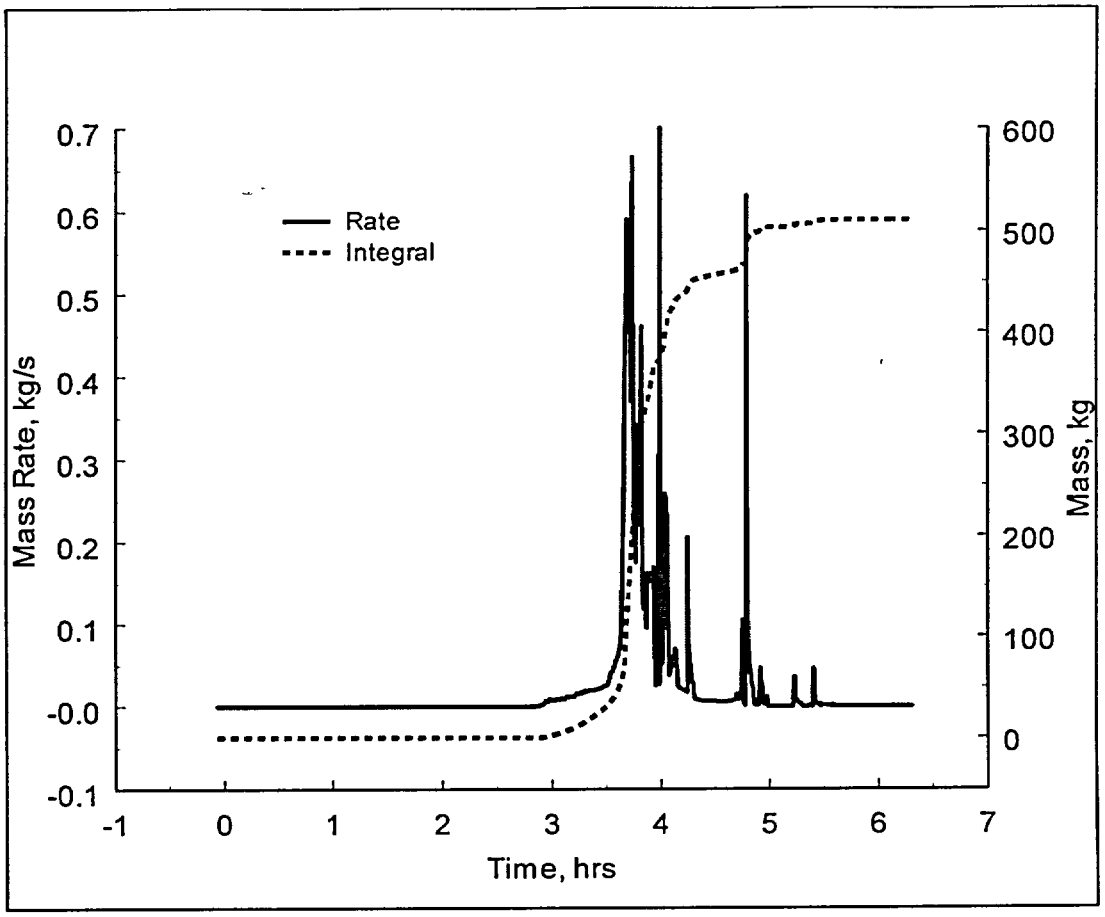

Figure 14. In-vessel hydrogen generation for MELCOR run 32.

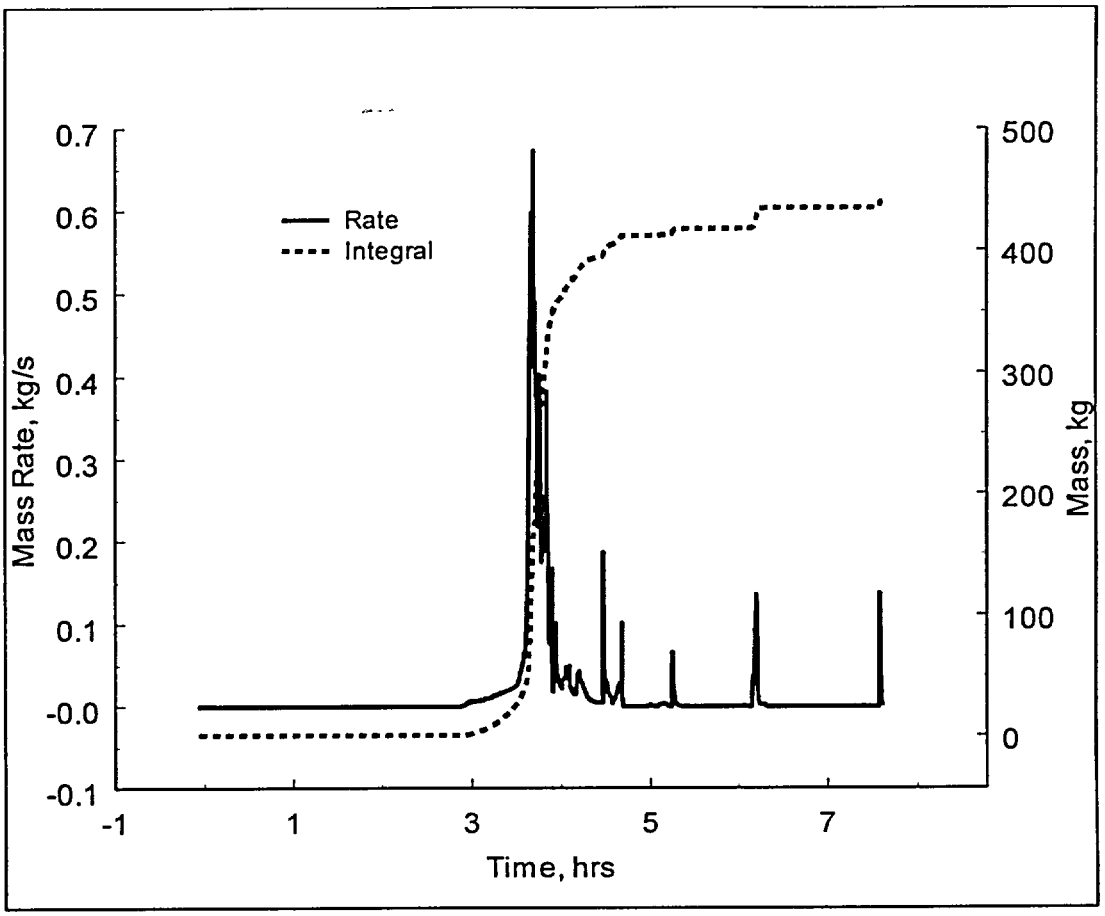

Figure 15. In-vessel hydrogen generation for MELCOR run 35.

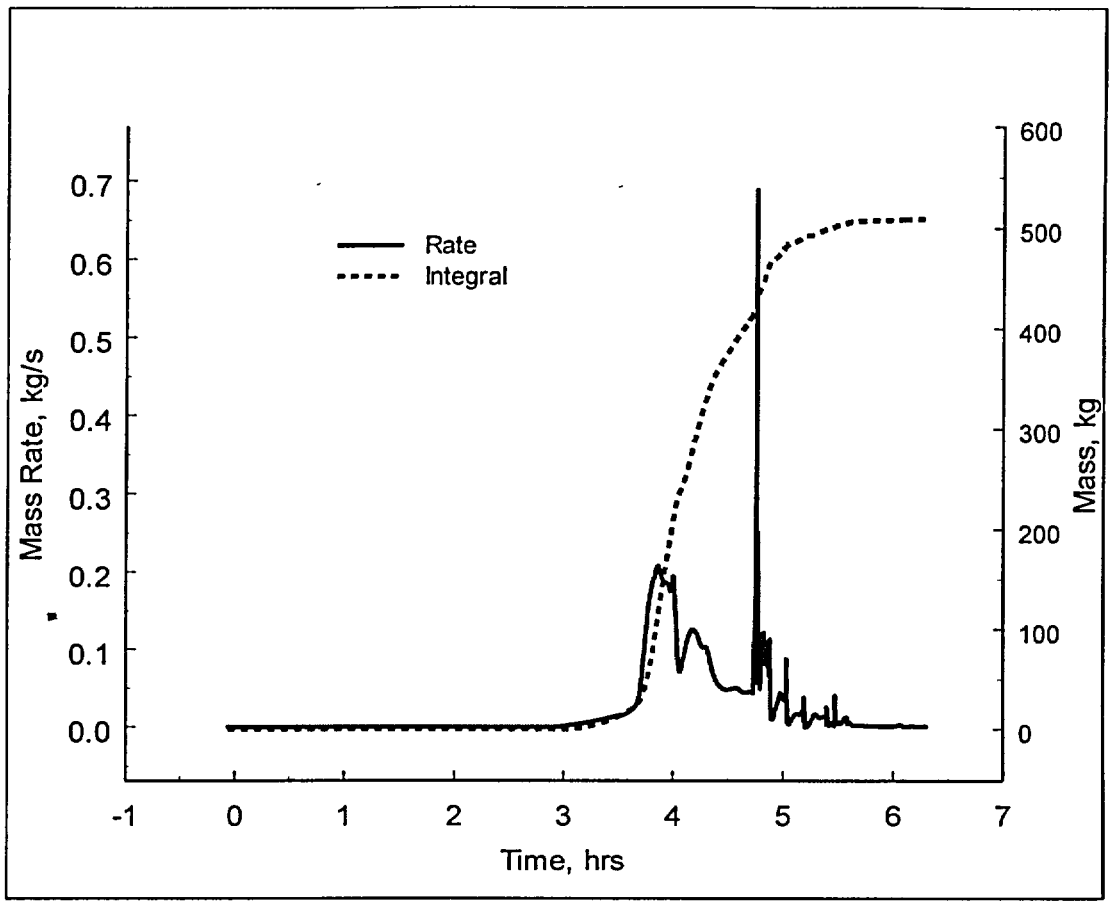

Figure 16. Hydrogen injection from pump seals for MELCOR run 32.

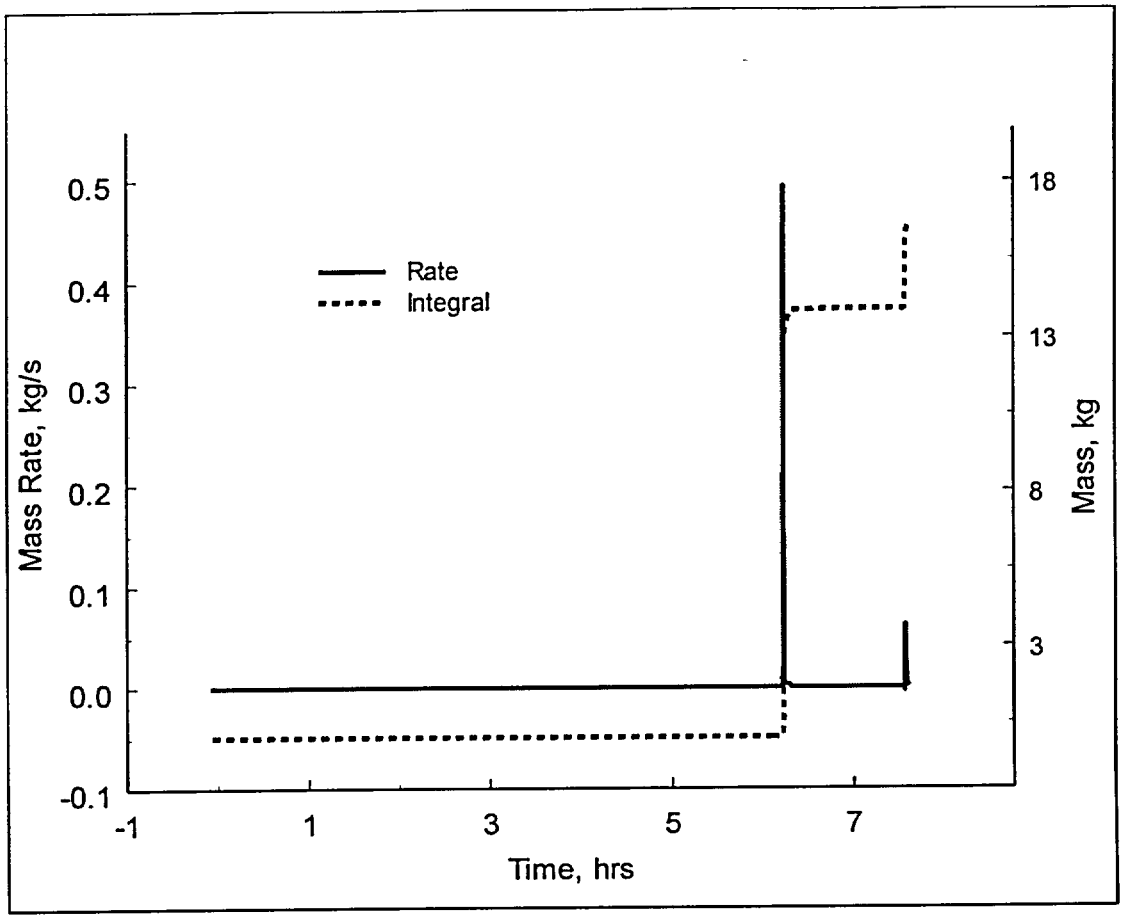

Figure 17. Hydrogen injection from hot leg failure for MELCOR run 35.

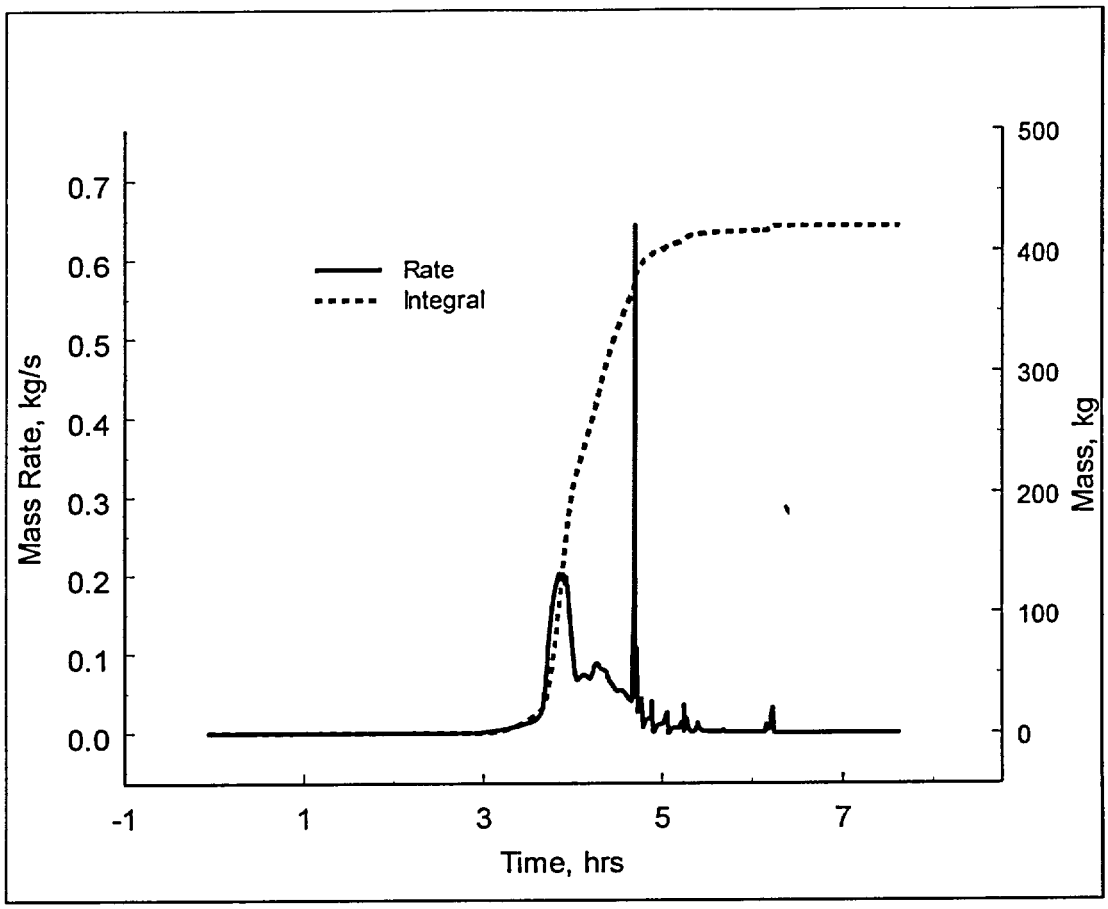

Figure 18. Hydrogen injection from pump seals for MELCOR run 35.

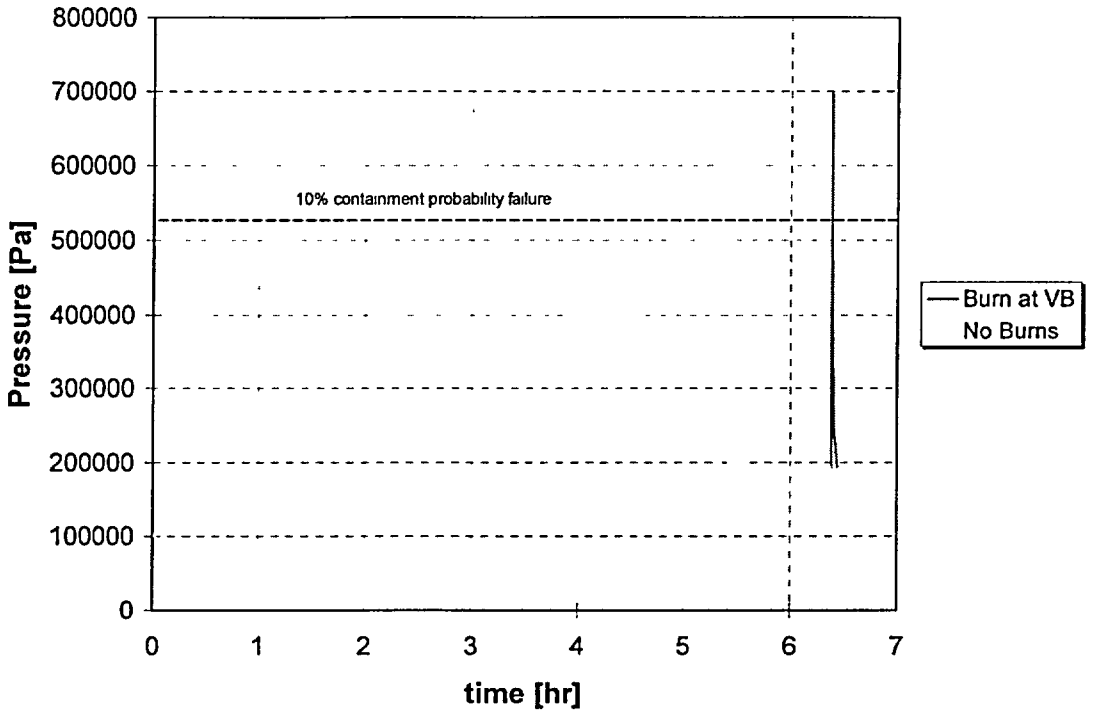

Figure 19. Containment pressure for MELCOR run 21 source term showing the overpressure that results from a delayed deflagration at the time of vessel failure.

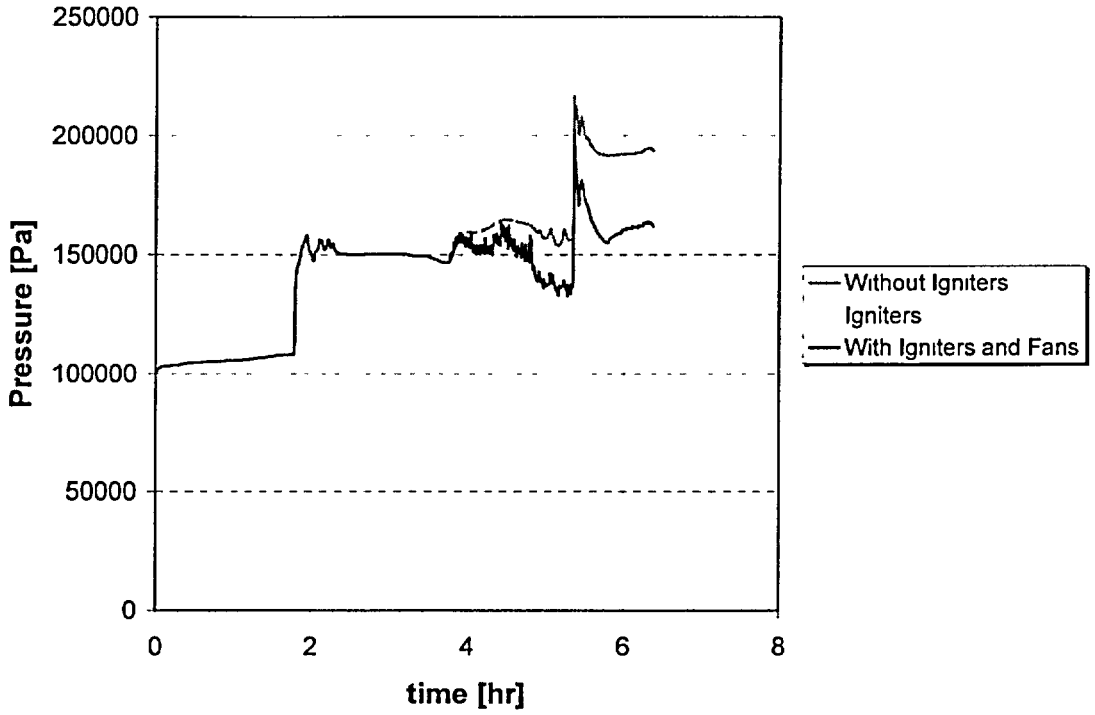

Figure 20. Containment pressure using hydrogen source term from MELCOR run #21.

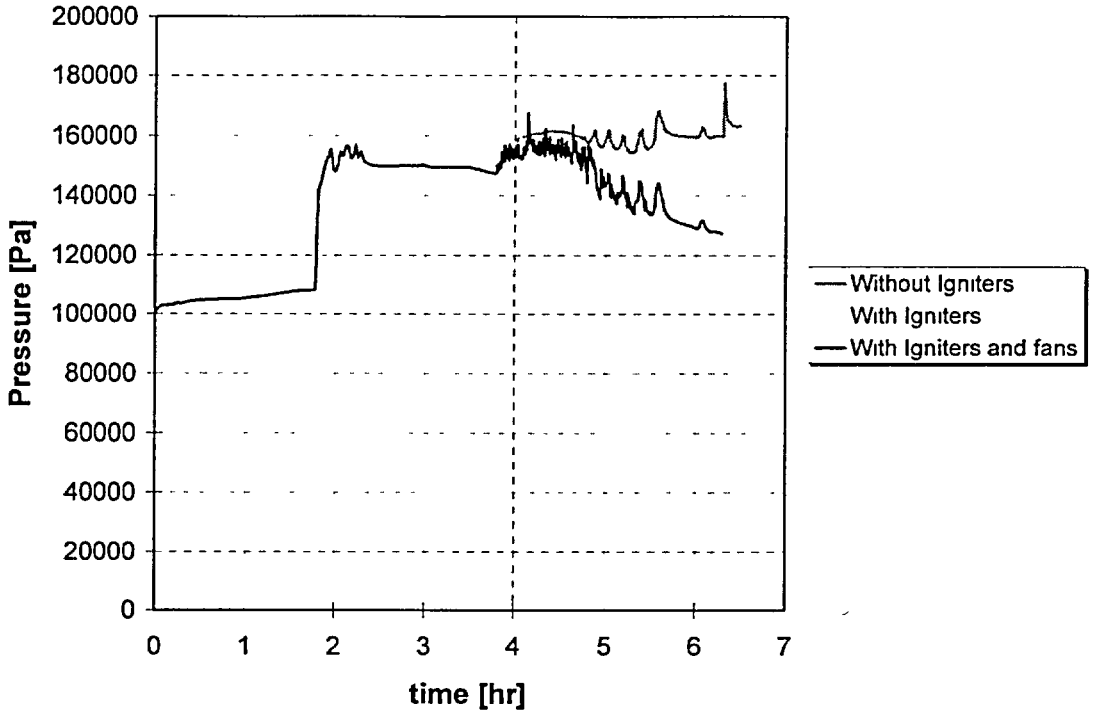

Figure 21. Containment pressure using hydrogen source term from MELCOR run #32.

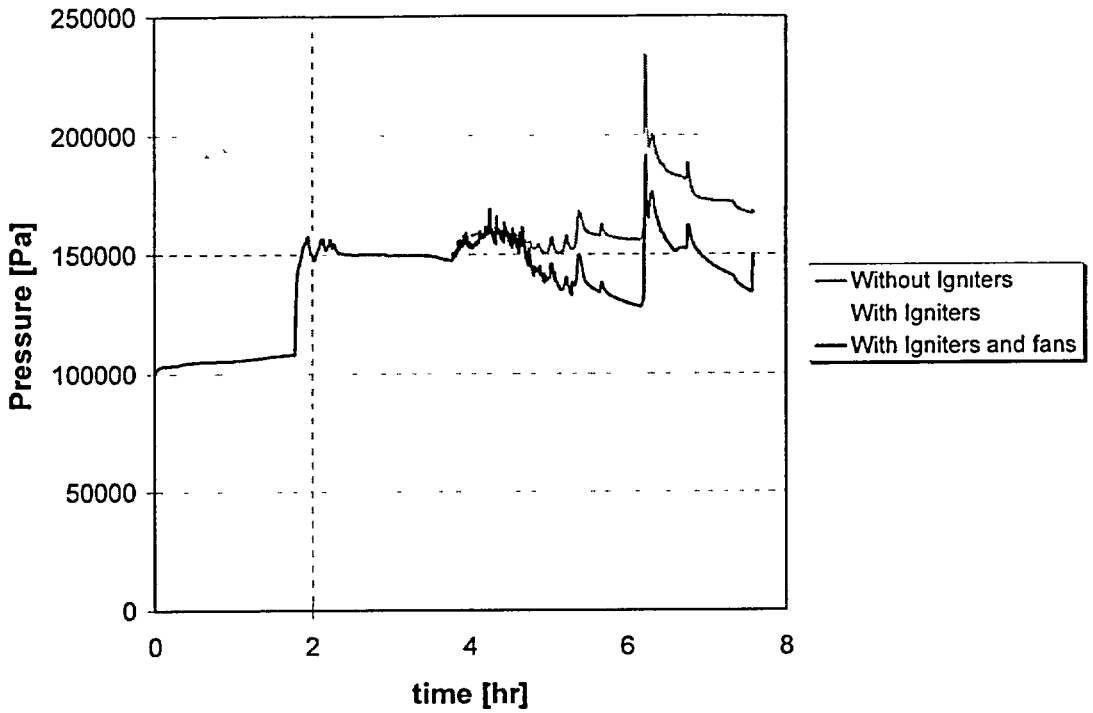

Figure 22. Containment pressure using hydrogen source term from MELCOR run #35.

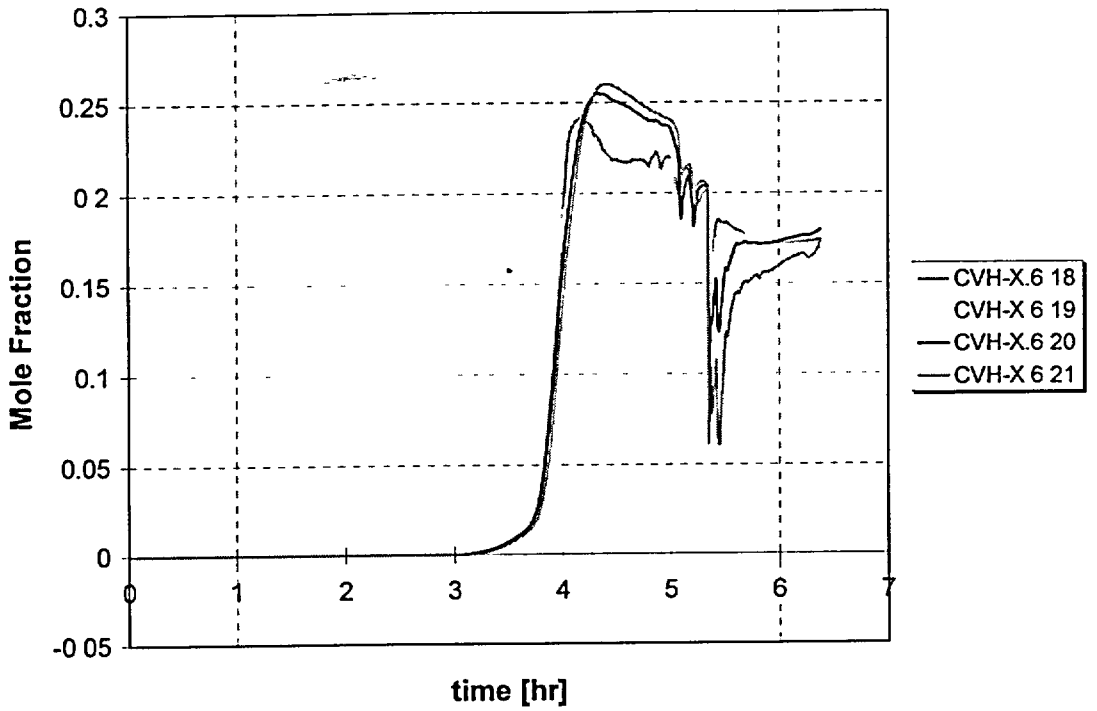

Figure 23. Hydrogen concentration in ice-bed for case without igniters, MELCOR run # 21.

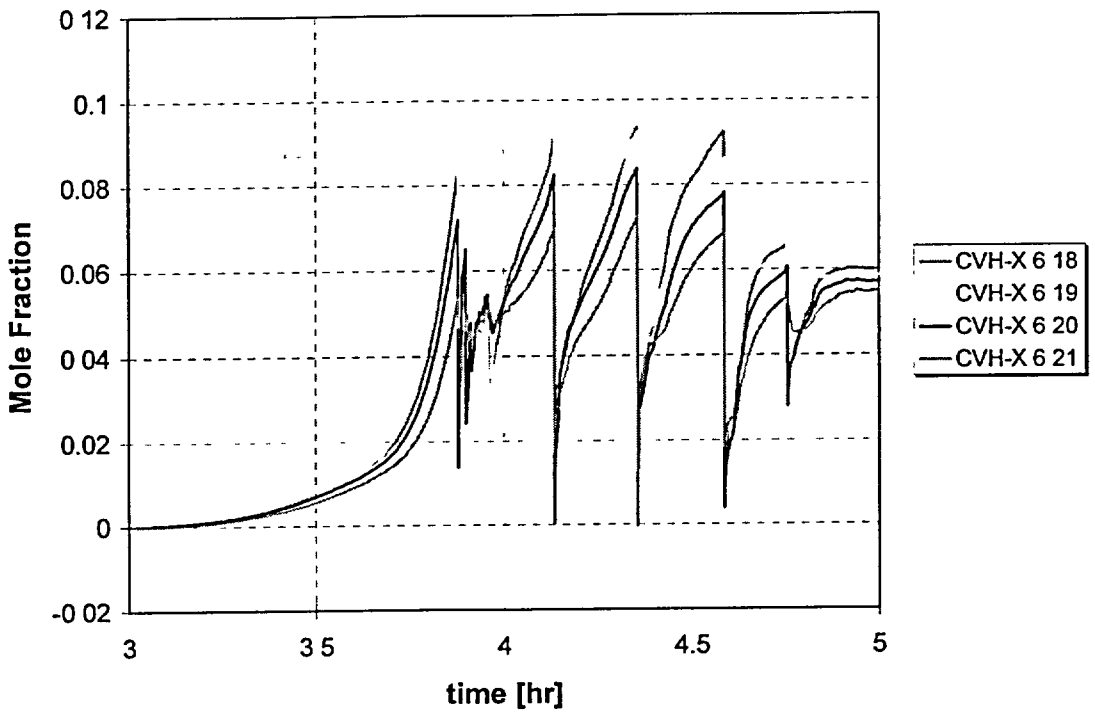

Figure 24 Hydrogen concentration in ice-bed for case with igniters, MELCOR run # 21.

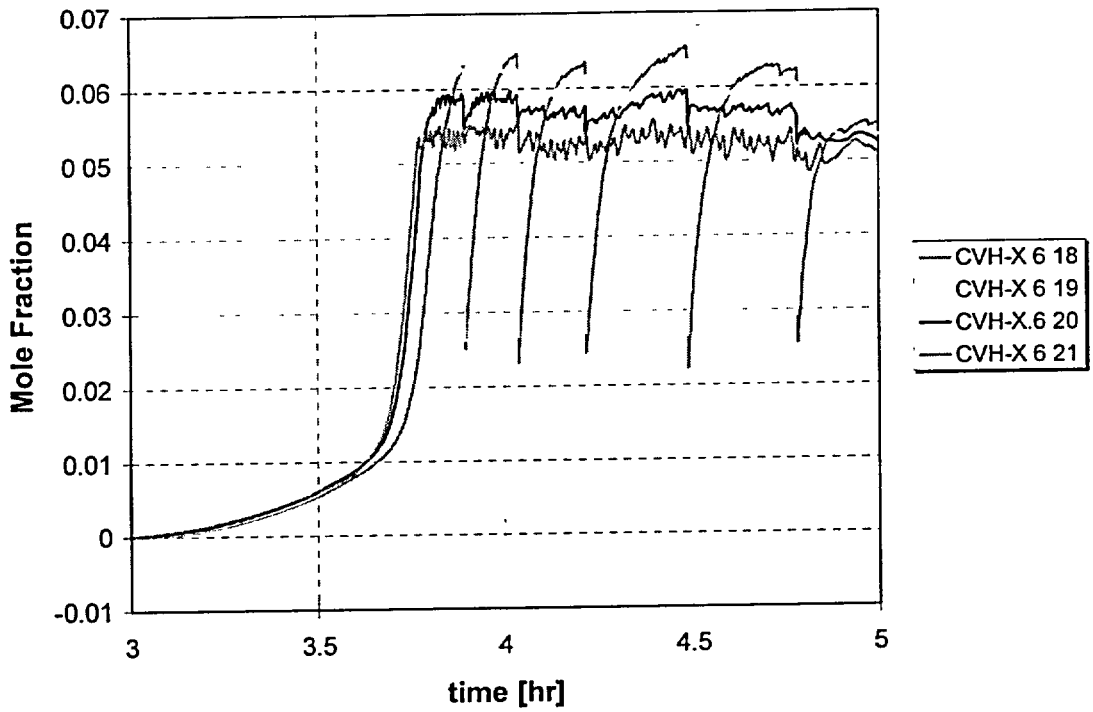

Figure 25. Hydrogen concentration in ice-bed for case with igniters and fans, MELCOR run # 21.

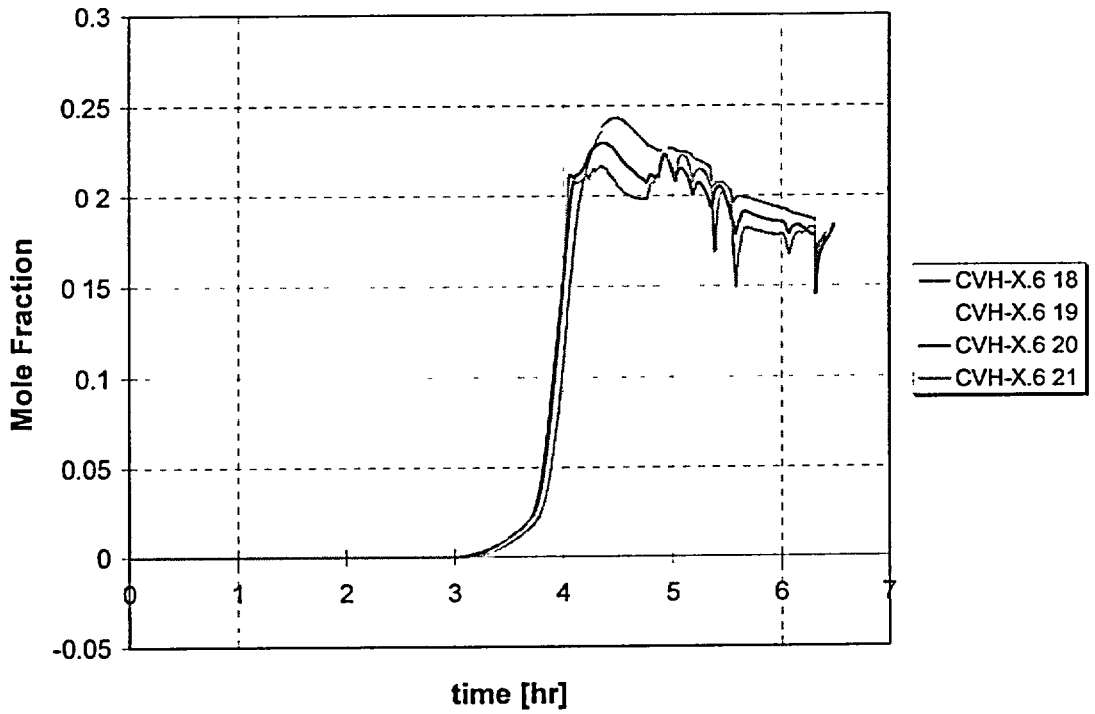

Figure 26. Hydrogen concentration in ice-bed for case without igniters, MELCOR run # 32

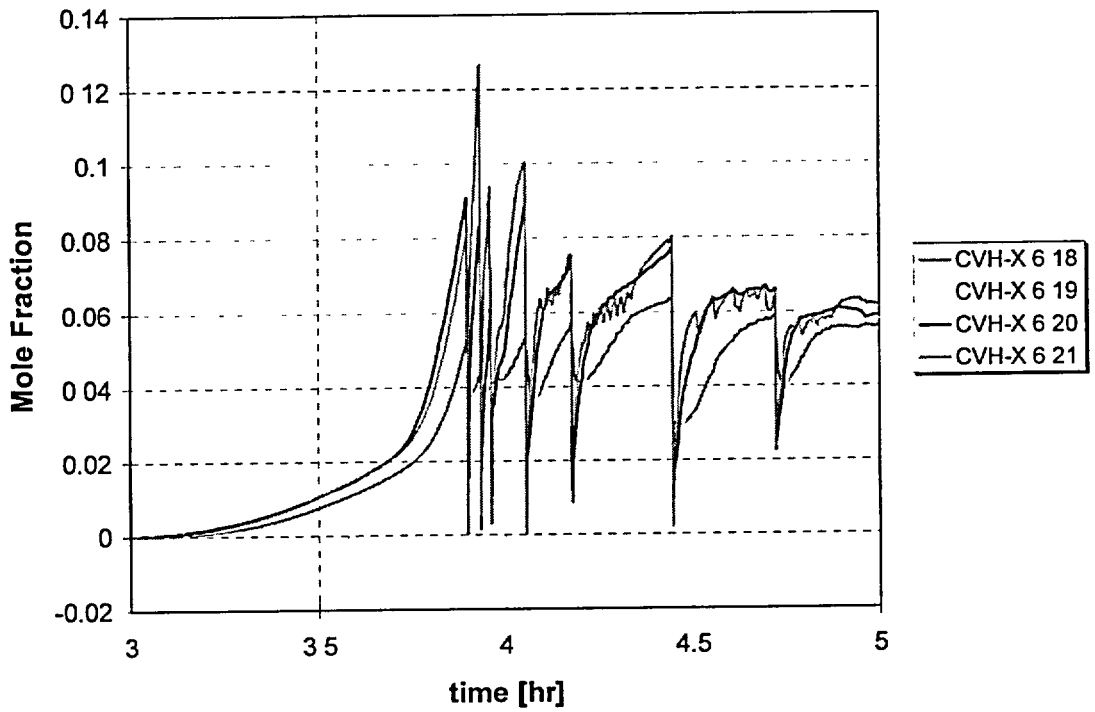

Figure 27. Hydrogen concentration in ice-bed for case with igniters, MELCOR run # 32

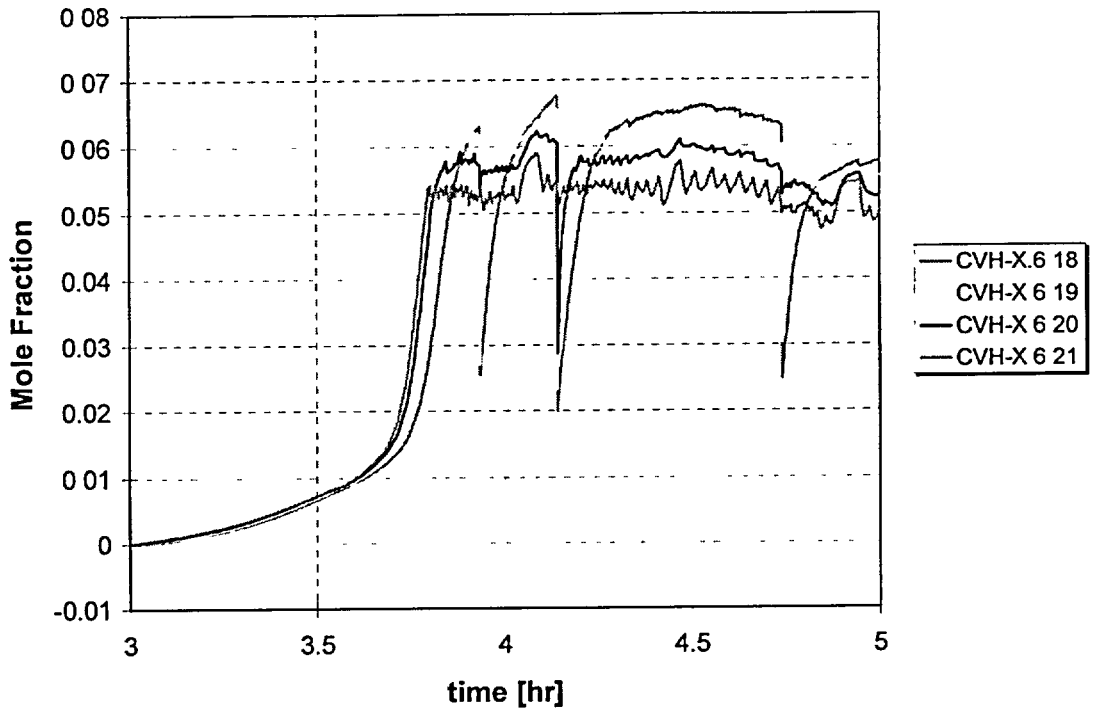

Figure 28. Hydrogen concentration in ice-bed for case with igniters and fans, MELCOR run # 32

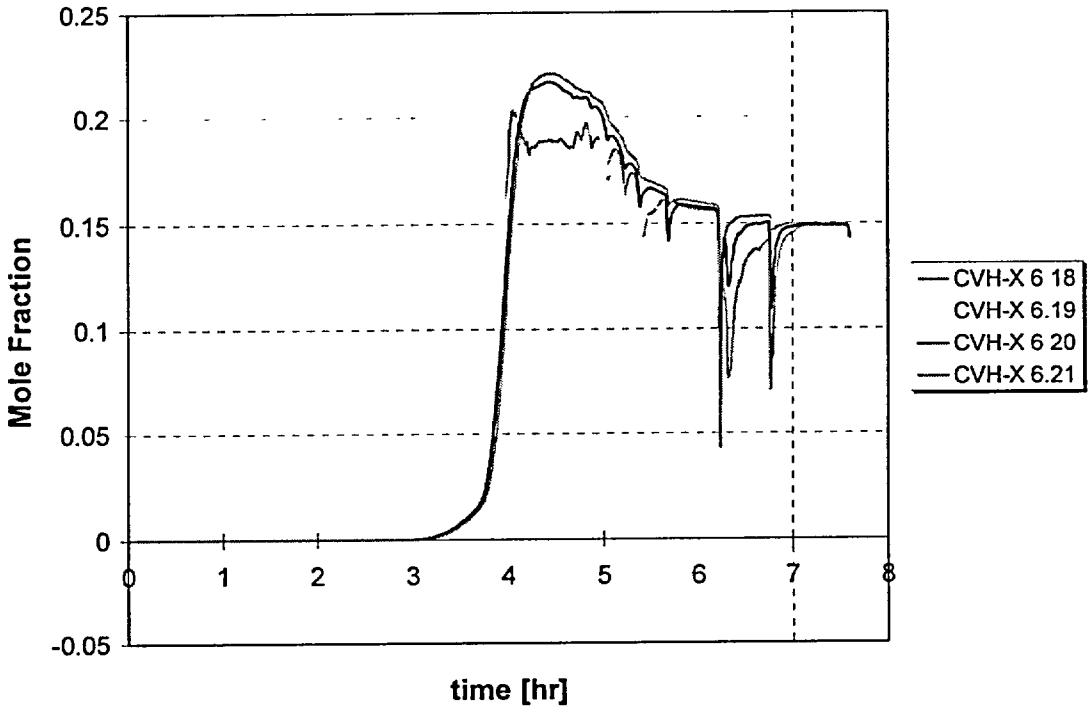

Figure 29. Hydrogen concentration in ice-bed for case without igniters , MELCOR run # 35.

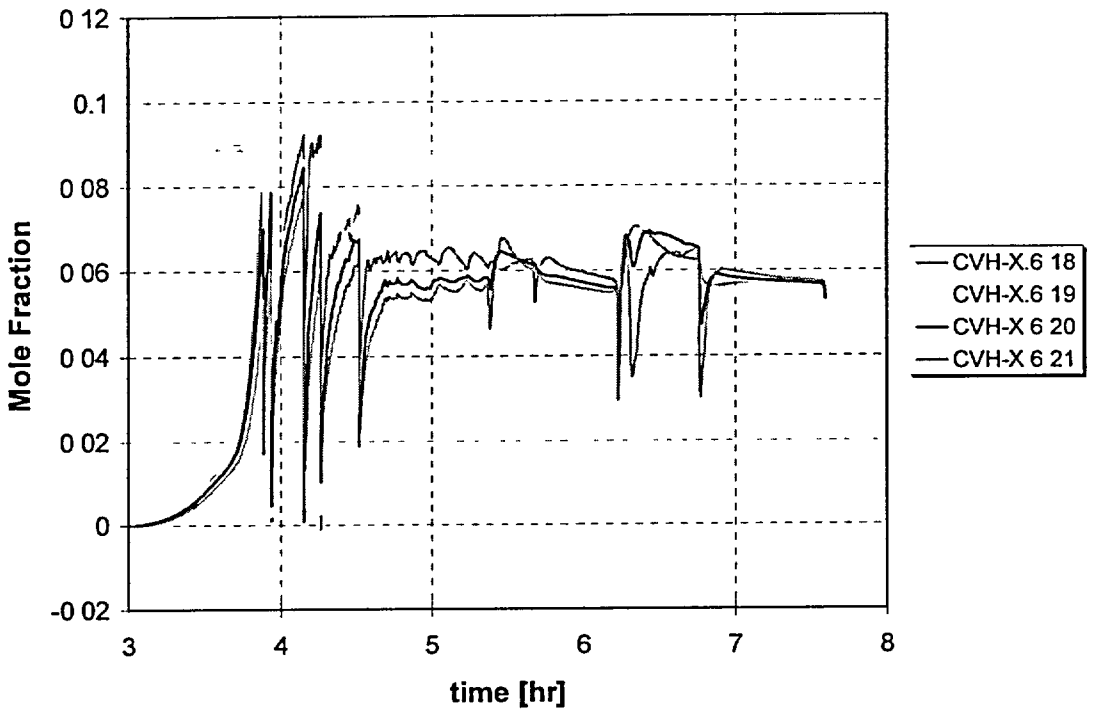

Figure 30. Hydrogen concentration in ice-bed for case with igniters , MELCOR run # 35.

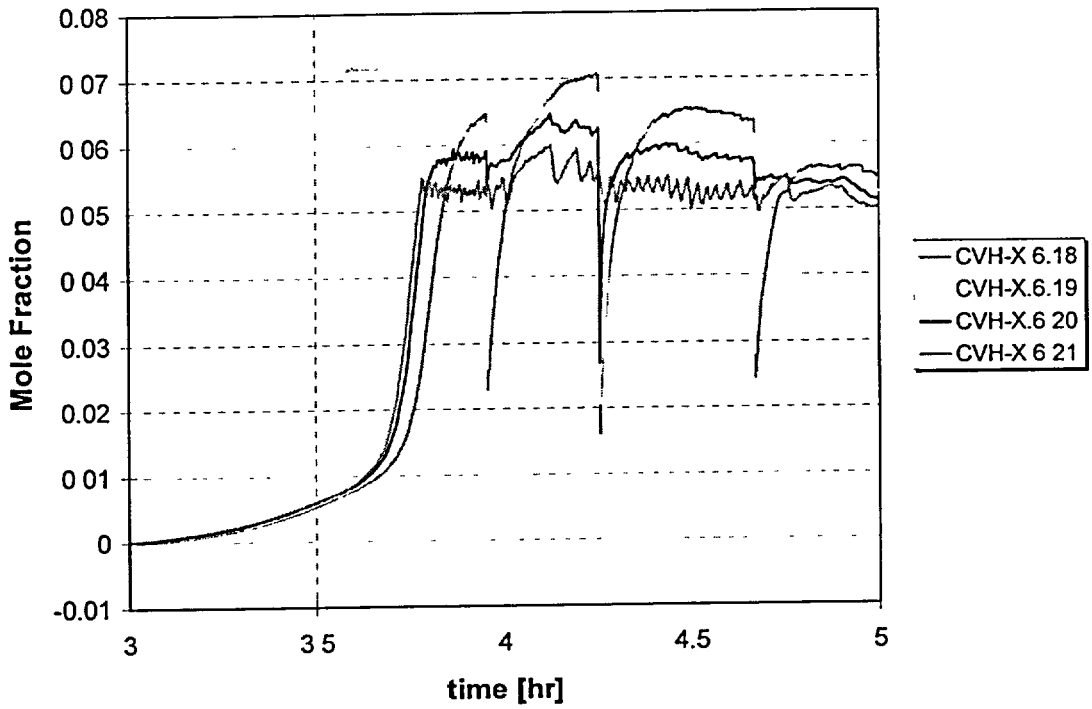

Figure 31. Hydrogen concentration in ice-bed for case with igniters and fans , MELCOR run # 35.

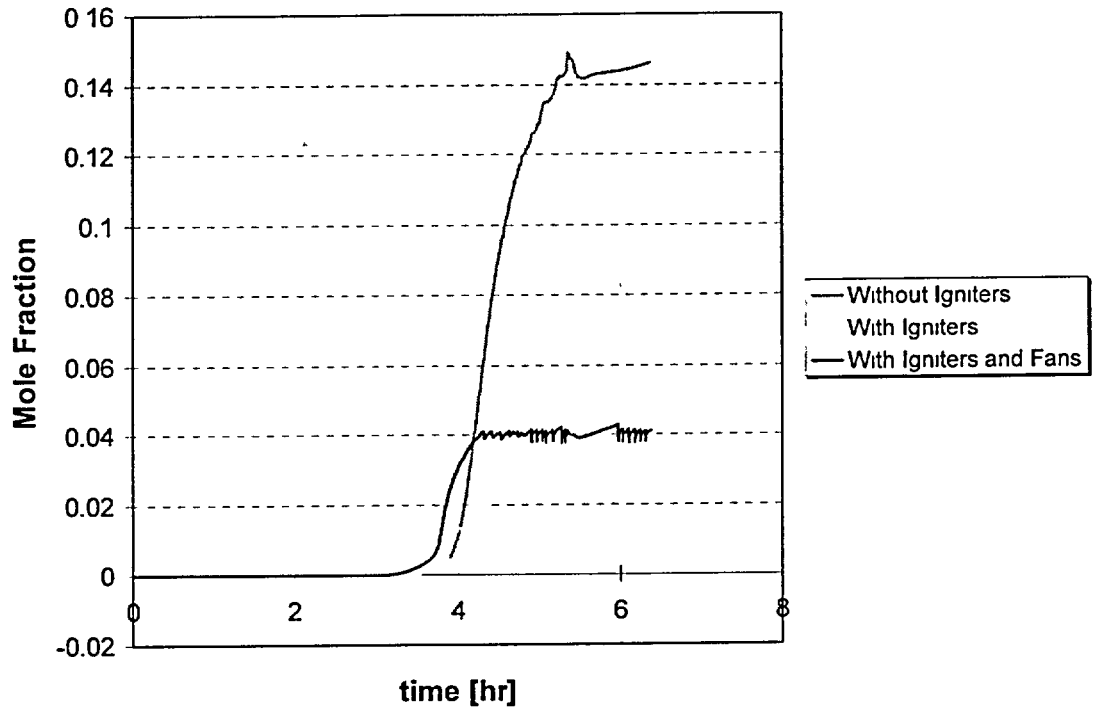

Figure 4 Hydrogen concentration in upper containment (compartment #24) for MELCOR run #21.

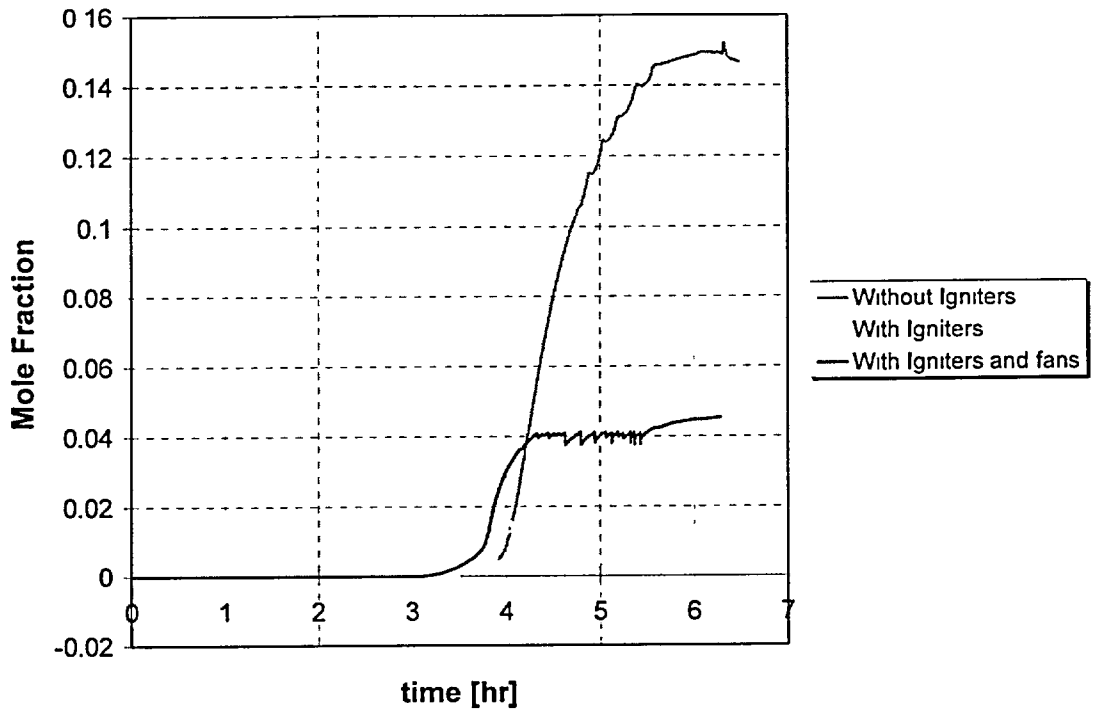

Figure 33. Hydrogen concentration in upper containment (compartment #24) for MELCOR run #32.

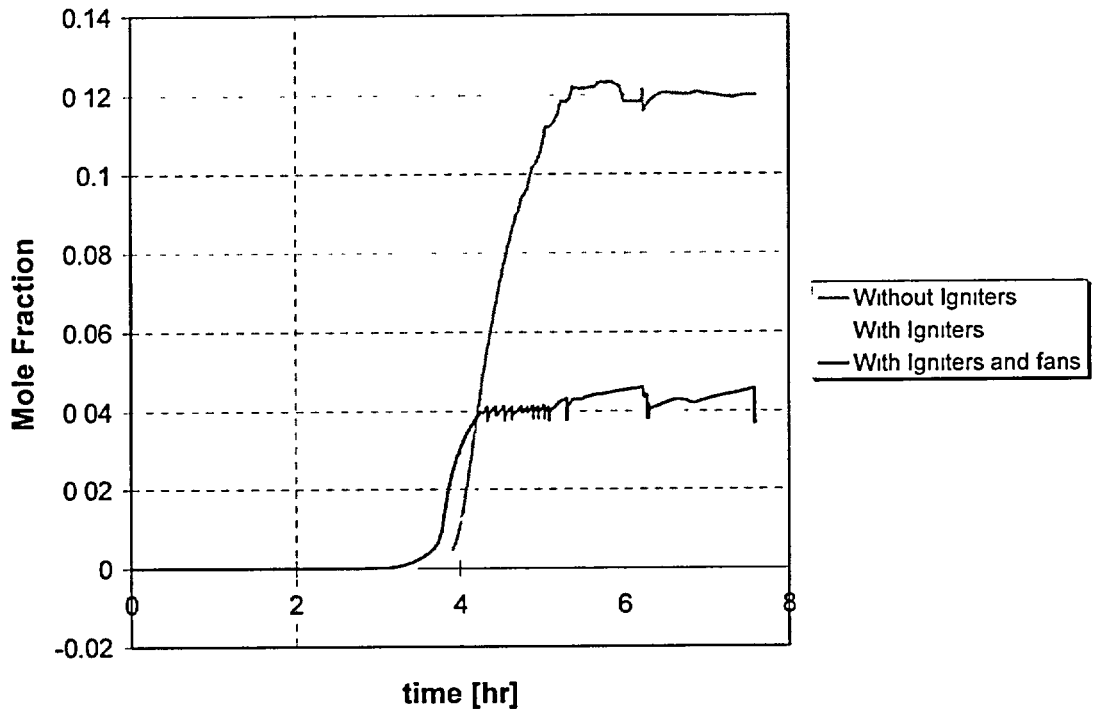

Figure 34. Hydrogen concentration in upper containment (compartment #24) for MELCOR run #35

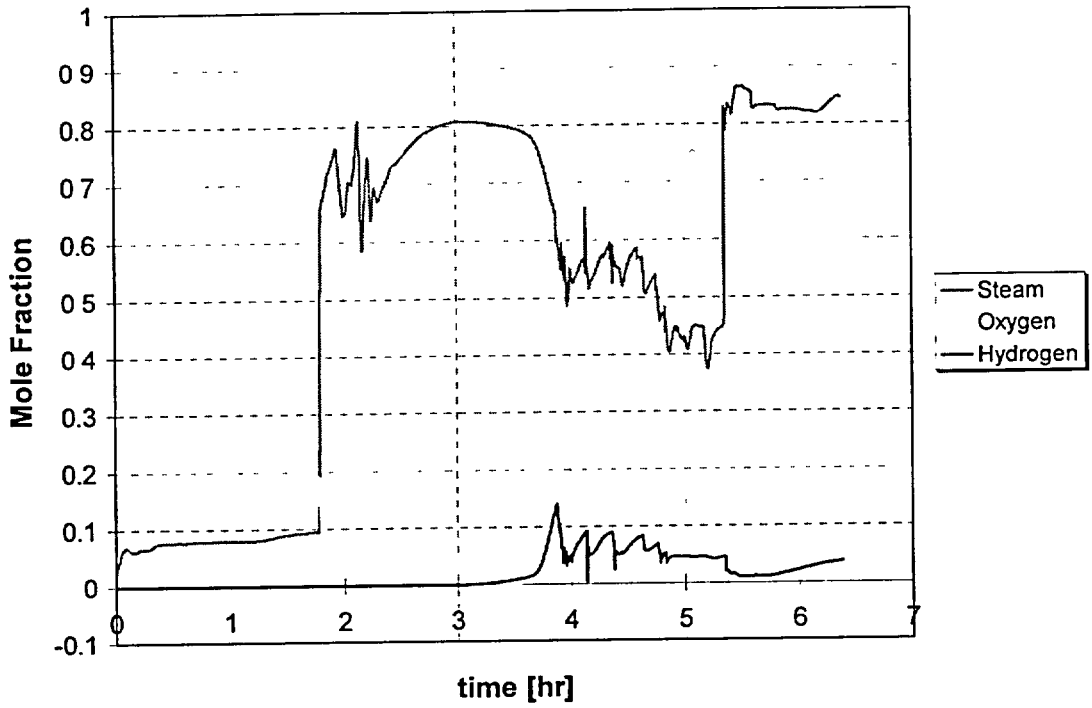

Figure 35. Containment atmosphere composition in compartment #9 (lower containment) for MELCOR run 21.

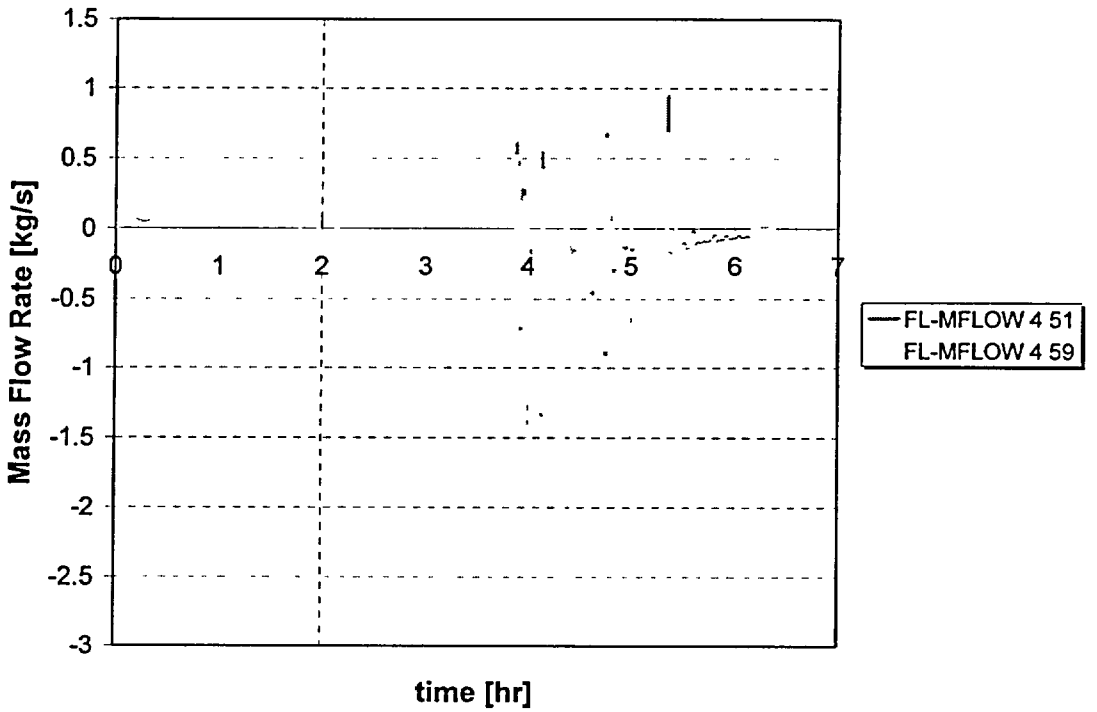

Figure 36. Oxygen flows for the refueling drains, showing the transfer of oxygen from the upper containment to the lower containment (negative flows).