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Response to Request for Additional Information
Regarding the Pilgrim Individual Plant Examination (IPE)
Submittal (TAC No. M74451)

Enclosed is Pilgrim Station's response to the NRC RAI related to the internal event analysis submitted by us in response to Generic Letter 88-20. If you have any questions, please contact Mr. Jeffrey Keene, Regulatory Affairs Department Manager, at (508) 830-7876.

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ETB/nas/Rap95/IPERESP

Enclosure: As stated

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Response to The RAI Regarding the Pilgrim IPE Submittal (TAC No. M74451)

Introduction

The Pilgrim Individual Plant Examination (IPE) is a living model that is updated to reflect changes to plant configuration and performance. It is continuously enhanced through on-going peer reviews and the increasing skills and knowledge of our IPE analysts. BECo's response to the NRC Request for Additional Information (RAI) dated April 17, 1995, takes full advantage of the following enhancements made to the Pilgrim IPE over the past three years:

1. HPCI dependency on Room Cooling has been eliminated based on engineering evaluation.
2. ADS success criteria has been modified, as a result of Appendix R and Modular Accident Analysis Program (MAAP) studies, to reduce the number of SRVs required for success during non-LOCA events.
3. DC power success criteria has been modified to take credit for the "battery eliminator" design feature of the new higher capacity 125 VDC Chargers installed in 1992 and 1993.
4. Low Pressure Injection credit for post Containment failure has been eliminated based on an ongoing IPE reassessment.
5. Recovery Actions have been developed for the following:
    - SBO Situations
    - Common Cause Breaker Failures
    - Alternate power feeds to B1 & B2

Thus, BECo's responses to the RAI questions are based on the current 1995 Pilgrim IPE, unless otherwise noted. For instance, RAI question 5(a) asks for the impact on Core Damage Frequency (CDF) if more recent Loss of Offsite Power (LOOP) events are considered. BECo responds to this question by calculating the change in the 1995 IPE CDF when the latest (1995) LOOP frequency data is substituted for the original (i.e., prior to 1992) LOOP frequency data.

The 1995 IPE also incorporates valuable feedback from the RAI questions themselves. In particular, RAI question 7 provided BECo with important insight to help support its decision to remove the Low Pressure Injection credit for post Containment failure.

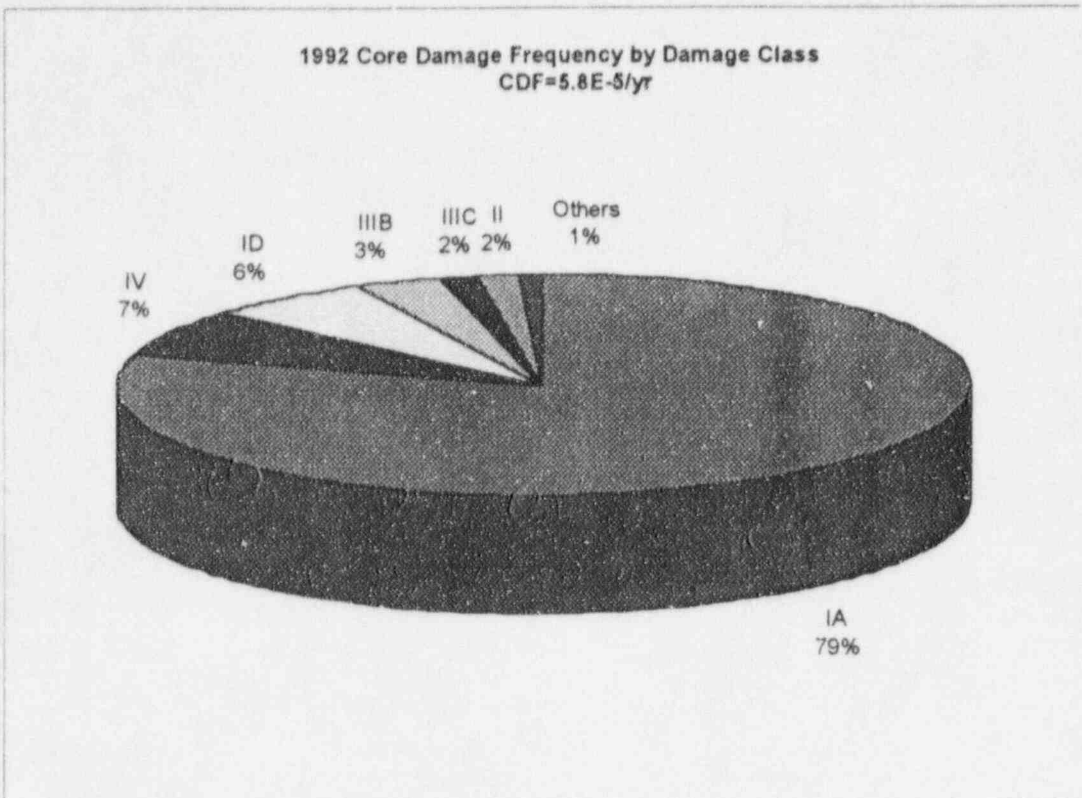
The 1995 IPE calculates a CDF of 2.84E-5/year compared to a CDF of 5.85E-5/year calculated by the original IPE. The original IPE and 1995 IPE results are compared, using Initiating Event and Damage Sequence contributions, in the following four charts. These charts show that the dominant damage class for both the 1992 and 1995 IPEs remains "IA". However, the absolute CDF contribution of this damage class is reduced by about two-thirds in the 1995 IPE because the HPCI room cooling dependency is eliminated, ADS success criteria is improved, and the failure rate performance of HPCI and RCIC is improved.

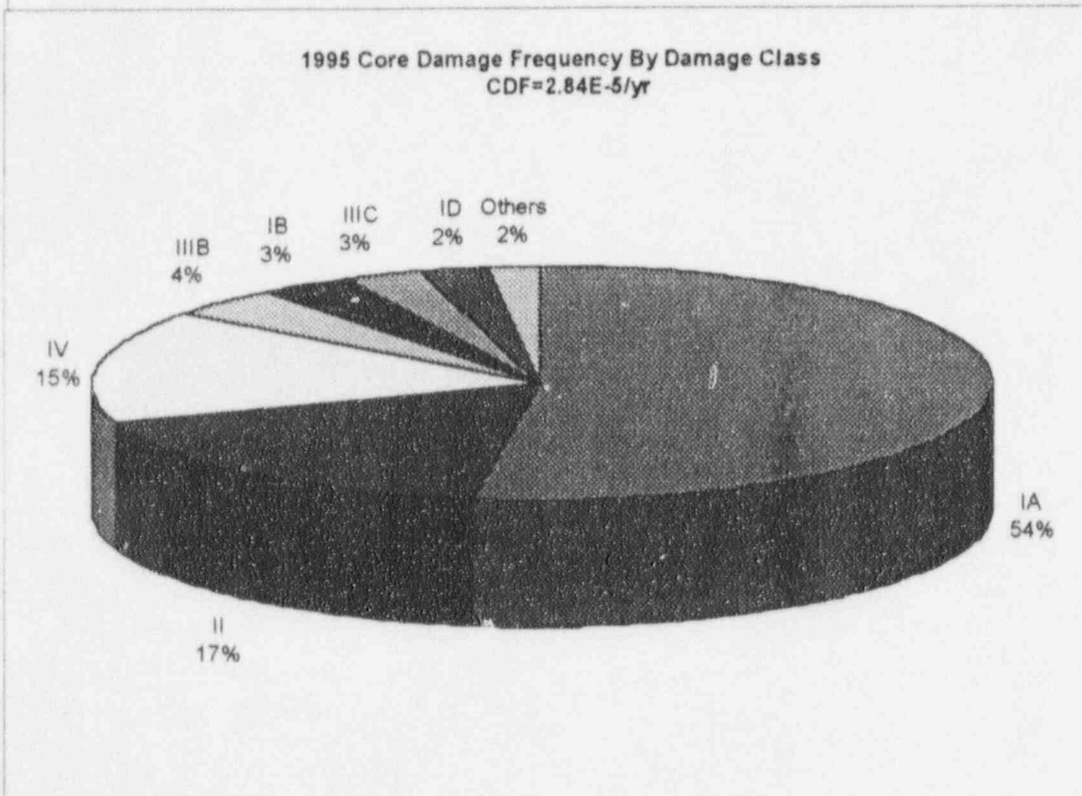
The 1995 IPE Damage Sequence "II" shows an increase in both its absolute CDF and percentage CDF contribution, compared to the original IPE. This is due primarily to the elimination of the

Low Pressure Injection credit for post Containment failure that is discussed in the response to RAI question 7.

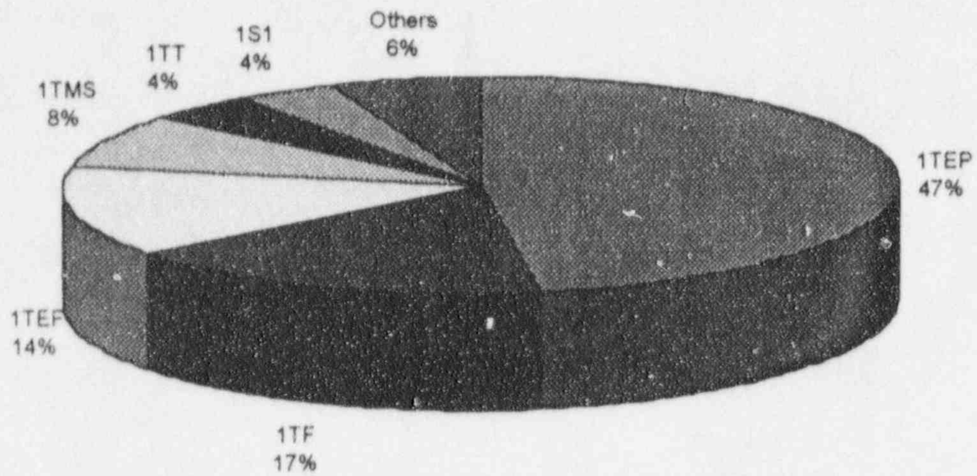
The "1TEP", "1TEF", and "1TF" Initiating Event absolute CDF and percentage CDF contributions are lower for the 1995 IPE because of the model enhancements discussed previously. The 1995 IPE "1TMS" Initiating Event absolute CDF contribution did not change significantly from the original IPE value; however, its CDF percent contribution did increase over the original IPE value because, for a given absolute CDF contribution, the percentage contribution increases when the overall CDF is reduced.

Additional insights to the changes between the 1995 and original IPEs are found in BECo's responses to the individual RAI questions.

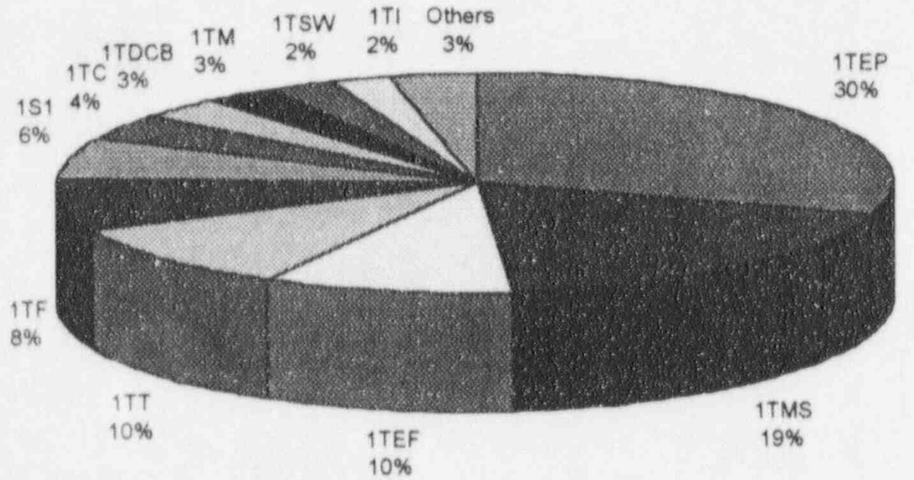

1992 Core Damage Frequency by Damage Class
CDF=5.8E-5/yr
IV
7%
ID
6%
IIIB
3%
IIIC
2%
II
2%
Others
1%
IA
79%


1995 Core Damage Frequency By Damage Class
CDF=2.84E-5/yr
IV
15%
IIIB
4%
IB
3%
IIIC
3%
ID
2%
Others
2%
IA
54%
II
17%

1992 Core Damage Frequency By Initiating Event
CDF=5.8E-5



1995 Core Damage Frequency By Initiating Event
CDF=2.84E-5



Boston Edison Response to NRC Questions (NRC Letter dated April 17, 1995):

1. Regarding the internal flooding analysis:

(a) Provide a discussion of how spray-induced equipment failures were addressed and their impact on the core damage frequency (CDF) or provide the basis for not considering them as part of the IPE's flooding analysis;

Spray induced equipment failures were not considered in the Internal Events IPE. Page C.4-19 (section C.4.5.2) states that the effects of spray on equipment was not evaluated. The reasons for this are as follows:

1. Spray induced equipment failures were assumed to occur when a pipe or weld break allows water to gush, or spray, out of the break and onto equipment, and then eventually onto the floor where the flooding action begins.

2. The PNPS flooding analysis relied on the results of previously performed flooding studies. These studies were conservative and bounding analyses which assumed design basis flooding levels in the areas affected. The equipment damage due to flooding envelopes the spray induced equipment damage.

The possibility for spray induced effects were addressed in the Pilgrim Station External Events IPE (IPEEE) report, submitted to the NRC in 1994, as follows (from section 4.12):

NRC Generic Letter 88-20, Supplement 4 lists the following Fire Risk Scoping Study issues to be addressed in IPEEE Fire analysis.

1. Seismic/fire interactions.
2. Fire barrier assessment.
3. Effectiveness of manual fire fighting.
4. Effects of fire suppressants on safety equipment. (Total environment equipment survival.)
5. Control systems interactions.

The seismic/fire interactions issue consists of three components: (1) seismically induced fires, (2) seismic actuation of fire suppression systems, and (3) seismic degradation of fire suppression systems. The evaluation supporting the resolution of this issue was performed via a plant walkdown.

The walkdown consisted of a visual examination of fire hazards within plant systems (flammable or combustible liquids or flammable gases within tanks, vessels, piping, cylinders, etc.); visual examination of the effects of inadvertent suppression system actuation; and a visual examination of fire suppression equipment and the potential effects the suppression would have in the event of a seismic event concurrent with a loss of fire suppression system integrity.

The walkdown also looked at what impact inadvertent actuation of fire suppression systems would have on plant equipment. For the most part, actuation of water based systems would wet down cabling. It is assumed that for the short duration of wetting, cables will be unaffected. In other cases, plant design has already accounted for a suppression actuation and potential damage to plant equipment. For example, in the Reactor Building, elevations 23'0" and 51'0" have berms and ramps to contain water from the water curtain thus preventing the flooding of important equipment. These areas also have spray shields to protect equipment from water exposure from above.

Some equipment has spray guards around them where they come in close proximity to pipes (especially high energy lines). Some are guarded in this manner when they sit under or near a fire sprinkler.

(b) *The submittal provides conflicting information on the contribution of internal flooding to overall CDF. On page C.4-23, the CDF from internal flooding is given as 7.87E-7/year, while in Table 3.4-2 it is given as 2.3E-7/year. Explain why these values are different and identify the correct value.*

The calculation used on page C.4-23 was intended to be an approximation of the CDF due to flooding, to give the reader an idea of the order of magnitude of the number. This calculation looked at the relationship between the loss of feedwater initiating event frequency and the feedwater pipe rupture frequency. This ratio is 4.3E-2. This ratio was applied to the flooding initiating event because of the similarity of the two events, and a rough CDF was produced.

The CDF due to loss of feedwater had been calculated to be 1.83E-5. The CDF due to flooding was subsequently calculated to be (1.83E-5) x (4.3E-2) = 7.87E-7. The correct CDF due to flooding was 2.27E-7. This was accomplished by the fault tree analysis software, using the internal flooding initiating event frequency (8.2E-3 per year) and its effects on plant systems to give a more accurate calculation of core damage frequency.

2. *It is not clear whether recirculation pump seal loss-of-coolant accident (LOCA) as an initiating event was considered. The IPE's frequency for small LOCA is almost a factor of 3 less than frequencies typically seen in probabilistic risk assessments (PRAs) that consider this initiating event. Please explain how seal LOCAs as initiating events were addressed in the IPE, and provide the basis for the IPE's small LOCA initiating event frequency.*

The PNPS internal events IPE used the IDCOR methodology to choose the initiating events. The IDCOR methodology in Table D10-2 provides the method to be used for determining the small LOCA initiating event frequency.

The IDCOR methodology addresses recirculation pump seal leakage by allowing each plant to determine its own vulnerability to recirculation pump seal leakage. Quoting directly from Table D10-2 "If the plant has a recirculation pump seal design which is prone to leakage, then...Estimate the additional contribution from this source of LOCA and add to the baseline value." Pilgrim's seal design is not prone to leakage and so the baseline value for small LOCA initiating event was used.

The small LOCA initiating event frequency in the IDCOR methodology was based on the value given in "Characteristics of Pipe System Failures in Light Water Reactors, EPRI NP-438, EPRI, August 1977."

3. *The long battery ifetime, especially with operator actions to shed DC loads, contributes significantly to the low contribution of station blackout to CDF. The plant-specific data used in the IPE to calculate recovery of offsite power are based on an exponential curve fit to two points; this curve fit results in much lower cumulative probabilities for failure to recover offsite power after 10 hours compared to data typically seen in PRAs or compared to NSAC-147 Figure 2-1 data.*

   (a) *Provide the basis for using an exponential curve fit based on two data points only.*

   The plant specific data used to generate the referenced exponential curve was derived from the followi.., hree complete losses of offsite power events that occurred at Pilgrim betw en anuary 1, 1975 and September 30, 1989:

   (1) 5/10/77: 2 hours a. 40 minutes
   (2) 2/6/78: 2 hours and minutes
   (3) 11/19/86: 0 hours an 3 minutes

   The observation that only two da points were used to fit the curve may have been due to the difficulty in discerni g the third data point on Figure 3.1-1 of the IPE. The third data point is in the pper left hand corner of the figure, partially obscured by both its own curve and th adjacent data point corresponding to the NUREG/CR-5032 reference curve.

   There is a broad range of distributions that n be fitted to three data points. We knew from NUREG/CR-5032 that recovery imes for the loss of offsite power could be fitted with varying degrees of accuracy to exponential, lognormal, Wiebull and gamma distributions. At the time of our 1992 data analysis we had access to computerized analytical tools for the evaluation of exponential and lognormal distributions, and of these, the exponential distribution offered the best fit.

   The data analysis supporting the 1992 IPE submittal took three exceptions to the information reported in NSAC-147:

   (1) NSAC-147 did not identify the 11/19/86 Pilgrim event as a complete loss of power. However, our plant records indicated the 23 Kv source was de-energized for 3 minutes during this event.

   (2) NSAC-147 described a loss of all offsite power event occurring on 11/12/87. This event was evaluated in our data base as a preferred loss of offsite power (i.e., loss of both 345 Kv sources only). We did not consider it an appropriate event for inclusion in our loss of all offsite power risk calculations because it occurred while the 23 Kv source was <u>electively</u> removed from service for a <u>once-in-a-lifetime</u> plant

enhancement to install a Station-Black-Out-Diesel Generator as part of our Safety Enhancement Program (SEP) modifications. The circumstances surrounding the elective removal of the 23 Kv source from service were unique because the plant had been in cold shutdown for over a year and decay heat was negligible. Therefore we concluded that this event had no relevance in risk calculations intended to evaluate the non-recovery probability of the loss of all offsite power as a function of the way Pilgrim is and will continue to be operated, maintained, and configured over its remaining life.

(3) The third exception taken by the 1992 IPE data analysis concerned the out-of-service duration NSAC-147 assigned to the 2/6/78 loss of all offsite power event. The 1992 IPE data analysis used two (2) hours and seven (7) minutes for the out-of-service duration based on plant records, while NSAC-147 reported eight (8) hours and fifty four (54) minutes for the same event. We have re-visited plant and REMVEC records to help clarify this discrepancy. The result of this reassessment, while not conclusive, provides support for the use of the NSAC -147 reported duration of eight (8) hours and fifty four (54) minutes for the 2/6/78 event.

Based on our decision to change the out-of-service duration estimate of the 2/6/78 event, an updated non-recovery probability calculation was performed. This calculation also included a fourth complete loss of offsite power event that occurred at Pilgrim on October 30, 1991 (after the close of the initial IPE data review period), and which lasted one (1) hour and forty nine (49) minutes.

The change to an eight (8) hour and fifty four (54) minute duration for the 2/6/78 event had a strong impact on the calculated Pilgrim LOOP non-recovery probabilities as shown in the following table (original values appear in Table C.2-1 of the 1992 IPE submittal):

Time (hrs)	Cumulative Non-Recovery Probability		Conditional Non-Recovery Probability	
	Original (3 Events)	1995 (4 Events/1 Revised)	Original	1995
2	4.10E-1	6.79E-1	4.10E-1	6.79E-1
5	1.01E-1	4.31E-1	2.46E-1	6.34E-1
12	3.82E-3	1.49E-1	3.79E-2	3.45E-1
15	9.40E-4	9.40E-2	2.46E-1	6.34E-1
24	1.40E-5	2.40E-2	1.49E-2	2.55E-1

Note that the updated non-recovery probabilities are somewhat larger than the original 1992 values and represent very conservative estimates compared to NSAC-147 Figure 2-7 results. These updated values were calculated using the same computational methodology applied to the original data, however, with a lognormal distribution providing the best fit this time.

The 1995 revised LOOP non-recovery probabilities result in a modest, 3.5% increase in CDF over the original non-recovery probabilities.

(b) *Discuss how the IPE process addressed extended losses of offsite power that could result from salt-spray or extremely high winds.*

Pilgrim Station's susceptibility to, and coping mechanisms for, extended losses of offsite power are fully discussed in Appendix C Section C.2 "Loss of Offsite Power" of the IPE. Specific reference is made to Section C.2.3, pages C.2-6 through C.2-20, for the LOOP event tree descriptions and quantification. While the dominant cause contributor to extended losses of offsite power is severe weather (e.g., phenomena such as salt-spray or extremely high winds), the IPE Analysis is general and independent of the specific cause of the loss of offsite power.

4. *An initiating event frequency of 2.7E-4 was calculated for loss of salt service water (SSW), and a CDF of 3.0E-7/year contributing 0.5% to total CDF.*

(a) *Provide the basis for a loss of SSW system initiating event frequency of 2.7E-4.*

Loss of Salt Service Water (SSW) is classified as a "special initiator" and special initiator frequency estimates were derived in Section 3.1.2.2 of the IPE. SSW success criteria (and system failure definition) are presented in Table 3.1-4 of that section. The actual derivation, including the equations, plant specific component failure data, and Multiple Greek Letter (MGL) common cause factors, are presented in Section A.3.6.1 of Appendix A of the IPE.

Even though Pilgrim has not experienced a SSW loss, it has experienced several SSW pump losses, and the pump failure data in combination with selected common cause factors allows the SSW loss probability to be estimated using plant specific data.

(b) *Explain whether the contribution to total CDF of 0.5% is due to loss of SSW initiating event only or due to overall SSW unavailability.*

The CDF contribution of 0.5% obtained from Table 3.4-2 of the IPE is for the loss of SSW as an initiating event and does not include the contribution from overall SSW unavailability. The loss of SSW in its role as a support function is modeled separately in the IPE and the magnitude of its contribution to CDF can be estimated by reference to Table 3.3-1. This table identifies important common cause contributors including the common cause failures of all SSW pumps to start. The Fussell-Vesely (FV) measure for this event is 1.5E-2 (i.e., 1.5%). Thus it can be seen that the loss of SSW as a support function contributes somewhat more to CDF than its loss as an initiating event.

5. *The IPE defined two types of loss of offsite power (LOOP) initiating events: total LOOP and partial LOOP. Total LOOP was assigned a frequency of 0.142/year and contributed 14% to the total CDF, while partial LOSP was assigned a frequency of 0.475/year and contributed about 48%. The IPE credited modifications completed in 1987 to the switchyard and to the 345 Kv lines as reducing the frequency of partial LOOP by 50%. However, during 1992 and 1993 Pilgrim experienced LOSP events. There is a concern, therefore, regarding the effectiveness of Pilgrim's LOOP related improvements given its LOOP experience after completion of the IPE. It also appears that the IPE did not take into consideration Pilgrim's DG failure-to-run experience in the estimation of DG failure-to-run probabilities.*

(a) *If the more recent LOOP events were taken into consideration what would be their impact on the LOOP frequency as well as on the CDF?*

From January 1, 1975, through August 31, 1995 (20.7 years), Pilgrim has experienced twenty three (23) LOOP events. Nineteen (19) of these events involved the loss of preferred offsite power only, and four (4) events involved the loss of all offsite power. As discussed in our IPE submittal, our data analysis methodology is to include all LOOPs occurring during both power and shutdown modes of operation to maximize the size of the data base. The resulting LOOP frequencies are then multiplied by Pilgrim's historical capacity factor of 0.7 to obtain the yearly "power operation" LOOP initiator frequencies. The updated frequencies are as follows:

- Loss of Preferred Power: 19/20.7*.7 = 0.643/year
- Loss of All Offsite Power: 4/20.7*.7 = 0.135/year

Neither of these frequencies is further adjusted to account for the recent switchyard improvements made in 1994 and 1995 to reduce the probability of salt-buildup induced LOOPs. The adjustments made to the LOOP frequency as part of the initial 1992 IPE submittal overestimated the improvements expected from switchyard enhancements made in 1987. As a result of this lesson learned, we do not intend to credit the 1994 and 1995 improvements but will instead rely on the accumulation of additional performance data as the means by which the benefits of switchyard enhancements are reflected in a living calculation of LOOP initiator frequencies.

If the revised LOOP initiator frequencies are included in the original IPE Model without consideration of the other performance updates and enhancements developed over the past three years their impact on Pilgrim's CDF are as follows:

- Loss of Preferred Power: ≅ <u>8.5% CDF increase</u>

- Loss of All Offsite Power: ≅ <u>0-1 % CDF decrease</u>

However, as discussed in the introduction, the revision to the LOOP initiating frequencies is only one of many ongoing changes being made to the IPE, and the overall impact of all the changes is a net reduction in CDF.

(b) *Provide the basis for the DG failure-to-run estimates used in the IPE in lieu of Pilgrim's DG failure-to-run experience.*

The basis for the DG failure-to-run estimate of 3.54E-4/hr is referenced in Table A-10, page A-34 of the IPE. Two notes, 'f' and 't', are provided in that table to explain the derivation of the failure rate. Note 'f', page A-13, provides the documentation for the estimate of 1,413 total run hours for the DGs during the data assessment period. Note 't' explains that since no run-failures were recorded during the data assessment period, 0.5 failures were assumed. The assumption of 0.5 failures is a recognized method to estimate a failure rate when there have been no failures and success data is available. The DG failure rate is thus estimated as follows:

0.5 run-failures/1,413 run hours = 3.54E-4 run-failures/hr

It is important to note two things regarding the IPE analysis of DG performance. First, as demonstrated above, the IPE did in-fact use plant specific performance to estimate the DG run failure rate. Second, there were DG failures during the IPE data assessment period. However, these were all classified as incipient start failures and were appropriately considered in the DG start failure rate also referenced and documented in Table A.10.

6. *The IPE estimated that Manual Shutdown has an initiating event frequency of 3.89/year and a contribution of 8% to the total CDF. However, the submittal provides little information on what constitutes "Manual Shutdown." Please:*

(a) *Explain what initiators are included in "Manual Shutdown."*

The submittal scram history includes 12.08 years of operating experience and is documented on Attachment A.13 of Appendix A. Each event in the scram history was evaluated and placed into one of the transient categories appearing in Table A-14 and shown below:

- Manual Scram
- Manual Shutdown
- Loss of Offsite Power
- Reactor Trips
- Turbine Trips
- Loss of Vacuum
- Closure of MSIVs
- Loss of Feedwater
- Inadvertent Relief Valve Opening

There were 27 events classified as Manual Scrams and 20 as Manual Shutdowns. These two categories were combined to form the "Manual Shutdown" transient category with a yearly frequency of:

(27+20)/12.08 = 3.89 events/year

The Manual Shutdown category includes all those events in which the reactor was manually shutdown for either a planned or forced outage and for which none of the other transient categories was appropriate. The practice of manually "scramming" the reactor to achieve a faster shutdown was generally stopped after about 1986. A quick scan of Attachment A.13 yields the following "typical" Manual Shutdown events:

- Shutdown to replace B & C main steam relief valves (page A-85)
- Shutdown to perform IE Bulletin No. 75-01 weld inspections (page A-86)
- Shutdown for refueling outage (page A-96)
- Shutdown to enter Drywell (page A-98)

(b) Discuss the associated sequences that comprise the 8% of the CDF contribution.

Manual shutdown initiated sequences account for 19% of the new requantified CDF of 2.84E-05. This is potentially misleading in that the CDF contribution from manual shutdown initiators has only risen 15%, from 4.5E-06 to 5.14E-06, which compared with the smaller total CDF value results in the relatively high 19% value.

The increase in contribution reflects the increase of TW sequences due to the removal of credit for post containment failure low pressure injection.

The manual shutdown initiated sequences consist of approximately equally high contributions (7% each) of ATWS and TQUX sequences, followed by smaller, equal contributions (2.5% each) of TW and TQUV sequences. It should be noted that one manual shutdown initiated sequence, a mechanical failure of control rods and failure to inject SLC, accounts for over 4% of the ATWS. This is high due to the relatively high initiating event frequency and not due to initiating event impact. The contribution of the other three sequence types follow the overall sequence contribution breakdown.

The relatively high initiating frequency of 3.89/year reflects the high amount of plant shutdowns experienced during 1975-1989. Recent plant experience indicates far less shutdowns. Therefore, as recent plant history is incorporated, a smaller contribution from manual shutdowns is expected.

7. *Consideration of the effects of loss of containment cooling on the ability to cool the core are important for accidents that release energy into the containment, as for example during long-term station blackout or during LOCA. The submittal provides a good discussion of how core cooling is maintained by recirculation from the suppression pool and by injection from external sources of water; however, we need clarification on the following:*

(a) *In section 3.6.1.3, where the impact of loss of containment cooling on maintaining core cooling is summarized, it is stated that high pressure coolant injection (HPCI) and reactor coolant isolation cooling (RCIC) can be aligned for long-term injection from the condensate storage task (CST) and that HPCI will not trip on high backpressure. It is not clear, however, if loss of RCIC due to trip on high backpressure was considered. Explain how the model treated loss of RCIC on high backpressure.*

An important setpoint with respect to the operation of the RCIC system is the turbine exhaust setpoint. The Pilgrim RCIC turbine exhaust trip setpoint is set at 46 psig, well above the pressures expected during any design basis event.

Because of this relatively high trip setpoint, the Pilgrim IPE models assume RCIC operation during the loss of containment cooling event. The MAAP computer model includes RCIC in its analysis of the loss of containment cooling sequence. RCIC's high back pressure trip setpoint allows for extended RCIC operation during the loss of containment cooling sequence. The MAAP computer model compares the available Net Positive Suction Head (NPSH) with the NPSH required for system operation and determines whether RCIC will be available during the sequence.

(b) *In Section 3.1.6.3, it is stated that as suppression pool temperature rises, operators depressurize the vessel to maintain heat capacity temperature limits; this action would prevent the continued use of HPCI and RCIC (because these systems use turbine driven pumps) but allows core cooling with the low pressure injection systems such as LPCI or core spray. As suppression pool temperature rises, LPCI and core spray recirculation from the suppression pool is terminated due to net positive suction head (NPSH) concerns: Core spray will be secured at about 12 hours and LPCI will be secured at about 17 hours. Core cooling can then be maintained using the firewater crosstie for injection. In Section B.6 it is also stated that the CRD, condensate, or core spray aligned to the CST systems can be used, but these options are not addressed in Section 3.6.1.3 of the submittal. Discuss the extent to which firewater, CRD, condensate, and the core spray were credited in the analysis for injection under the circumstances discussed above. In addition, discuss the potential implication of long-term overfill of the containment and the suppression pool when external sources of injection are used.*

Injection from CRD, condensate, and core spray aligned to the CST are identified as possible sources of low pressure injection during the loss of containment heat removal only. Sequence Section 3.6.1.3 describes the results of the MAAP analysis of the loss of containment heat removal sequence. During the MAAP analysis, CRD, condensate, and core spray aligned to the CST were not credited.

No matter which source of low pressure injection is used, Pilgrim's EOP 1 requires all injection from outside containment be terminated when torus bottom pressure cannot be maintained below 60 psig. This action precludes any further increase in primary containment water level and is authorized because the consequences of not doing so may cause a loss of primary containment integrity. With a degraded core condition and a loss of containment integrity, substantial amounts of radioactivity may be released to the environment. The EOP's are based on a philosophy that preferentially chooses to maintain primary containment integrity in order to protect against the uncontrolled release of radioactivity.

(c) *Operator action to vent containment if containment cooling systems fail is considered [IPE, Section B.6]. The containment is vented with an 8-inch hardened vent line from the suppression pool wetwell, and the vent valves require nitrogen and DC power to open. The vent line is rated at 120 psig. The operator is instructed to vent when containment design pressure is approached, which is 56 psig. [IPE, page 2.3-30] Please discuss which core cooling systems are assumed to be available after venting.*

The existing event trees and the associated fault tree quantification assumed no core damage if injection systems were successful and containment pressure were successfully controlled. Consideration of injection systems remaining after venting was not included in the fault tree/event tree model.

The PNPS MAAP model used during the IPE process included the NPSH requirements for systems taking suction from the suppression pool. The MAAP model includes failing these systems when suppression pool water temperature and pressure exceed the NPSH limits for the pumps, or when suppression pool water temperature exceeds the temperature limit for HPCI and RCIC pump oil cooling.

(d) *Without containment venting, the containment will continue to heat up. The operators are directed to terminate all injection from external sources when the torus bottom pressure reaches 60 psig, which occurs at about 34 hours. [IPE, Section 3.6.1.3] Torus water temperature is about 300°F and is too hot for use by core cooling systems. With no injection to the vessel, water boils off and core damage occurs at about 39 hours. Containment failure is expected at about the time of vessel failure, which occurs at about 47 hours. This discussion implies* *that without containment cooling and without venting of containment, core damage will occur prior to containment failure. However, based on the event tree for station blackout and the discussion in Section B.8, it appears that credit was taken for core cooling after containment failure. ([IPE Figure C.2-3 and Section B.8] Our concern is how core cooling was maintained up to the time of containment failure:*

- *Discuss how core cooling is accomplished prior to containment failure when the containment is at high temperature and pressure and both containment heat removal and venting are not available because the operators are instructed to terminate all external injection.*

Ongoing review of the results of the IPE analysis shows that core damage occurs prior to containment failure, and the IPE analysis cannot take credit for successful core cooling after containment failure. The PNPS IPE model has been revised to show that core damage occurs prior to containment failure. The PNPS IPE has been requantified to reflect this change in philosophy.

This change in philosophy caused the event 'Reactor Coolant Inventory" with the designator QUV to be removed from all event trees where it appeared. The following sequences were affected:

Existing Sequence	Figure	Effect on the sequence
TWQUV	C.1-1	Credit for post containment failure injection removed. The sequence designator becomes TW
SL1 & 2	C.3-1	Credit for post containment failure injection removed.
ML1 & 3	C.3-2	Credit for post containment failure injection removed.
LL1	C.3-3	Credit for post containment failure injection removed.
AOUT1	C.3-5	Credit for post containment failure injection removed.
ISCS1	C.3-6	Credit for post containment failure injection removed.
ISLPCI1	C.3-7	Credit for post containment failure injection removed.
RL1, 4, 5, 8, and 11	C.4-6	Credit for post containment failure injection removed.
SORV1 and 3	C.4-7	Credit for post containment failure injection removed.
IORV1, 2, 3, 5 and 7	C.4-8	Credit for post containment failure injection removed.
LOOP1 through 4	C.2-1	Credit for post containment

Existing Sequence	Figure	Effect on the sequence
		failure injection removed.
LOOP9 through 14	C.2-3	Credit for post containment failure injection removed.
LOOP16 & 17	C.2-3	Credit for post containment failure injection removed.
LOOP19 & 20	C.2-4	Credit for post containment failure injection removed.
LOOP23 through 26	C.2-5	Credit for post containment failure injection removed.
LOOP29, 31, 33,34,36 and 37	C.2-6	Credit for post containment failure injection removed.
LOOP39, 41, 43, 46	C.2-7	Credit for post containment failure injection removed.

The following is the results of the requantification. Compare these results with those of Table 3.4-1 starting on page 3.4-4 of the IPE report.

Revised Table 3.4-1
Summary of Core Damage Frequency by Core Damage Sequence

Sequence Name	Damage Class	Core Damage Frequency (per yr.)	% CDF	Percent of Damage Class
LOOP 6	IA	8.37E-06	29.47%	56.07%
TQUX	IA	6.[illegible]8E-06	22.46%	42.74%
IORV4	IA	1.79E-07	0.63%	1.20%
Total Class IA		1.49E-05	52.56%	
LOOP18	IB	9.58E-07	3.37%	
ATWS13I	IC	8.62E-08	0.30%	
TQUV	ID	2.84E-07	1.00%	43.70%
LOOP38	ID	1.81E-07	0.64%	27.85%
LOOP5	ID	1.50E-07	0.53%	23.08%
IORV8	ID	2.24E-08	0.08%	3.45%
SORV4L	ID	7.42E-09	0.03%	1.14%
IORV6	ID	5.07E-09	0.02%	0.78%
Total Class ID		6.50E-07	2.29%	
TW	II	3.44E-06	12.11%	70.11%
LOOP 2	II	1.12E-06	3.94%	22.83%
IORV1	II	2.38E-07	0.84%	4.85%
TQUW	II	6.06E-08	0.21%	1.24%
IORV5	II	2.62E-08	0.09%	0.53%
SORV1L	II	5.93E-09	0.02%	0.12%
IORV7	II	5.75E-09	0.02%	0.12%
ATWS1I	II	5.54E-09	0.02%	0.11%
TLQUW	II	4.59E-09	0.02%	0.09%
Total Class II		4.91E-06	17.27%	
VR1	IIIA	2.10E-07	0.74%	72.16%
VR2	IIIA	8.10E-08	0.29%	27.84%
Total Class IIIA		2.91E-07	1.02%	
ML5	IIIB	1.06E-06	3.73%	90.06%
SL4	IIIB	1.17E-07	0.41%	9.94%
Total Class IIIB	IIIB	1.18E-06	4.14%	
ML2	IIIC	5.70E-07	2.01%	71.23%
LL2	IIIC	1.41E-07	0.50%	17.62%
ML4	IIIC	8.92E-08	0.31%	11.15%

Revised Table 3.4-1
Summary of Core Damage Frequency by Core Damage Sequence

Sequence Name	Damage Class	Core Damage Frequency (per yr.)	% CDF	Percent of Damage Class
Total Class IIIC		8.00E-07	2.82%	
VR4	IIID	9.00E-09	0.03%	85.23%
SL1	IIID	1.56E-09	0.01%	14.77%
Total Class IIID		1.06E-08	0.04%	
ATWS6NI	IV	1.80E-06	6.34%	40.96%
ATWS14NI	IV	6.75E-07	2.38%	15.36%
ATWS6I	IV	6.58E-07	2.32%	14.97%
ATWS2NI	IV	4.50E-07	1.58%	10.24%
ATWS7NI	IV	2.61E-07	0.92%	5.94%
ATWS14I	IV	2.45E-07	0.86%	5.58%
ATWS2I	IV	1.63E-07	0.57%	3.71%
ATWS7I	IV	8.94E-08	0.31%	2.03%
LL4	IV	2.10E-08	0.07%	0.48%
ATWS4NI	IV	2.01E-08	0.07%	0.46%
ATWS4I	IV	6.25E-09	0.02%	0.14%
ATWS21NI	IV	3.59E-09	0.01%	0.08%
ATWS9I	IV	1.20E-09	0.00%	0.03%
ATWS15I	IV	1.07E-09	0.00%	0.02%
Total Class IV		4.39E-06	15.47%	
AOUT2	V	1.00E-07	0.35%	50.00%
ISCS2	V	5.00E-08	0.18%	25.00%
ISLP2	V	5.00E-08	0.18%	25.00%
Total Class V	V	2.00E-07	0.70%	
Total CDF		2.84E-05		

Revised Table 3.4-2
Summary of Core Damage Frequency by Initiating Event

Initiating event	Core Damage Frequency (per year)
Partial loss of offsite power (345 Kv)	8.46E-06
Manual shutdown	5.26E-06
Full loss of offsite power (345 & 23 Kv)	2.78E-06
Turbine trip and reactor trip	2.78E-06
Loss of Feedwater	2.27E-06
Medium LOCA	1.70E-06
Loss of Condenser Vacuum	1.00E-06
Loss of DC bus B	9.36E-07
MSIV closure	8.11E-07
Loss of SSW	6.82E-07
Inadvertently opened safety relief valve	6.14E-07
Reactor vessel rupture	3.00E-07
Large LOCA	1.62E-07
Small LOCA	1.21E-07
Loss of DC bus A	1.09E-07
Main Steam Line break	1.00E-07
Internal flood	6.07E-08
Core Spray interfacing system LOCA	5.00E-08
LPCI interfacing system LOCA	5.00E-08
Reference line break	1.95E-08
Loss of RBCCW	1.38E-09

- *Without containment heat removal and without containment venting, the containment pressure can exceed the nitrogen supply pressure to the relief valves resulting in vessel repressurization and in loss of all low pressure injection systems; please explain how this was factored into the model.*

  This conclusion is correct. Analysis of MAAP results shows that high drywell pressure condition closes the SRVs at approximately 40 hours into the sequence. Because HPCI and RCIC are aligned to sources of water outside the primary containment, as the vessel repressurizes, these systems can be operated to maintain water level.

- *At some BWRs, the flow losses in the firewater system piping and fittings result in firewater injection to the vessel being unavailable if containment pressure exceeds about 100 psig; please discuss the effect of high containment backpressure on the ability to provide adequate injection with the firewater crosstie option.*

  The PNPS MAAP model for Fire Water Crosstie to RHR (FWXT) is based on a system flow curve which takes into account pump developed head, system flow losses, and backpressure inside the RPV or drywell to calculate system flow rate, depending on whether the system is being used for RPV injection or drywell spray. High drywell pressure can cause the SRVs to close and can cause repressurization of the reactor vessel. This in turn can result in the reduction of injection flow from the FWXT, and if backpressure exceeds approximately 120 psig, the MAAP model shows FWXT as unable to provide makeup to the RPV.

(e) *After containment failure, HPCI, RCIC, and CRD are assumed to be unavailable due to EQ concerns in the reactor building. [IPE, Section B.8] It is also stated that the firewater crosstie may be lost due to failure of the RHR injection lines upon containment failure. Please clarify the IPE's assumption for the availability of firewater injection after containment failure, and provide the basis for this assumption.*

This assumption was based on the statement made in section B.8 that physical damage to injection piping due to containment failure or high energy blowdown of the containment could occur. This statement was meant to underscore the vulnerability of the FWXT injection source after containment failure. In the PNPS PRA, the two locations which dominate the risk of containment breach are the drywell head and the containment vent line bellows. Containment breach at either of these two locations is not expected to impact FWXT injection. The statement quoted in the question is meant to stress that uncertainty in break location can lead to uncertainty in FWXT availability after core damage.

8. *The submittal's discussion on the resolution of USI A-45 is based on a "narrow" decay heat removal (DHR) definition, that being loss of containment heat removal. The IPE model, however, addressed DHR for both its core and containment heat removal functions. In order to resolve USI A-45 licensees were requested to examine DHR for its capability during both core cooling and containment heat removal phases and for all accidents except large LOCAs, anticipated transient without scram (ATWS), and interfacing systems LOCAs. Please expand the submittal's discussion on the resolution of USI A-45 (i.e., DHR redundancy, diversity, etc.) to include the DHR core cooling capability at the Pilgrim plant.*

The PNPS IPE submittal defined decay heat removal as removal of decay heat from the containment. Another possible definition of decay heat removal could include two other functions:

- Removal of decay heat from the reactor core to the containment
- Makeup of adequate coolant to keep the core covered with water.

The PNPS IPE considered these functions as part of the PRA.

Under the alternate definition of decay heat removal, the failure of this function would account for all level I results except large LOCAs, ATWS, and interfacing system LOCAs. A summary of where these accident classes are discussed in the IPE submittal is given below:

IPE Report Section	Accident Class Discussed
3.5.1	Class IA: Initiating event with a failure of high pressure makeup and failure to depressurize (TQUX)
3.5.2	Class IB: Station blackout (SBO)
3.5.4	Class ID: Initiating event with a loss of both high and low pressure coolant injection (TQUV)
3.5.5	Class II: Initiating event with failure of decay heat removal from the containment (TW)
3.5.7	Class IIIB: Small or medium LOCAs for which the RPV cannot be depressurized (S_1QUX or S_2QUX)
3.5.8	Class IIIC: Medium LOCAs for which there is inadequate makeup to the vessel (S_1V)

Each of these sections discusses the important assumptions, initiating events, hardware failures and human actions for the applicable accident class.

9. *It was stated by the licensee during the 12/20/94 conference call that the system unavailabilitites contained in Appendix B were not used for estimating the CDF; instead, the Appendix A "up-dated" component failure data were used in combination with system fault trees. Please provide the correct system unavailabilities for HPCI and RCIC used in the CDF estimation.*

It should be noted that none of the system unavailabilities presented in Appendix B were used in the CDF estimation. The system unavailability values presented in Appendix B were the result of solving functional fault trees and cannot be used to calculate CDF using current fault tree linking methodology. Earlier state of the art PRAs, such as the focused risk assessment completed in 1988, utilized support state methodology. This methodology uses top level, functional fault trees to model most plant systems, as opposed to the detailed component/part level fault tree models required to support the fault tree linking methodology used to calculate CDF in the current PRA. Therefore, the system unavailabilities presented in Appendix B are for reference only and were not used to calculate CDF.

As explained in Section A.2.1, most of the failure data used by the IPE was collected in the 1980's during a time when Pilgrim was experiencing performance problems. Many of these problems were addressed during Pilgrim's extended outage in 1987 and 1988. Since Pilgrim's restart in 1989, several critical systems have demonstrated significant performance improvements, including HPCI and RCIC. These two systems were selected for a pilot application of a five year moving average data base to help ensure that their failure rates were reflective of current performance. Whereas the stated cutoff date for IPE failure data had been 9/30/89, it was extended to 3/31/92 for HPCI and RCIC.

The HPCI and RCIC failure rate data appearing in Table A-10 and A-13, and used to quantify the IPE was derived from the latest data available through 3/31/92. Unfortunately, Appendix B had already been prepared prior to the decision to go with updated HPCI and RCIC failure rates, and the HPCI and RCIC probabilities contained in Table B.3-1 reflect the old failure rates. The revised HPCI and RCIC system unavailability values are:

- HPCI = 6.54E-2
- RCIC = 8.12E-2

10. *It is not clear from the submittal whether the impact of preinitiating human events associated with disabling a system due to miscalibration of critical instrumentation was considered. Please explain or provide the list of the miscalibration preinitiators that were considered in the analysis.*

The complete list of preinitiating human events is given in the answer to question 11 below, along with the guidance used in developing these events. No pre-initiating events due specifically to miscalibration of instruments were included in the IPE model. The inclusion of miscalibration initiators is being considered for future revisions of the model.

11. *It is not clear in the submittal what basis was used to assure that all important preinitiating events were included in the analysis. Typically, in a PRA an initial set of preinitiator human events is identified and then a screening process (either qualitative or quantitative) is used to help differentiate the more important preinitiator human events. Please explain your process and basis assuring that important preinitiator errors were not omitted from consideration in the HRA.*

The PNPS IPE fault tree development effort was undertaken using guidance contained in the PNPS Fault Tree Development Guide. The Fault Tree Development Guide dealt with human actions in section 5.5 "Operator Action Modeling". It says that operator actions that are performed from the control room and are proceduralized in the operators' normal, off-normal, and emergency operating procedures are to be included in the PRA model. The pre-initiating event "Operator fails to turn AC breaker fast transfer switch on" is of this type.

The other type of pre-initiating human events are dealt with in section 5.6 "Test and Maintenance Modeling". These would deal with the failure to restore a system after test or maintenance. This guide states that failure to restore a component or system to its safeguard position can result in the component being unavailable when required. The analyst must examine several factors, however, before including a restoration error in the model. First, many test and maintenance procedures require an operational test of a system or component following completion of the work to verify the system is operable. In some cases , even if a component is left in a wrong position or condition it automatically shifts to the proper condition when required. If neither of these factors is present, the analyst must determine whether or not the operator can tell from the control room that the component is in the wrong position and the operator is required to check the component status routinely. Otherwise, the probability of a restoration error must be included in the fault tree.

12. *It is stated in the submittal that "operation actions were initially assigned human-error probabilities (HEPs) determined by screening." It is not clear from the submittal what screening values were used for the preinitiator events (as, for example, for events involving alignment of systems following test or maintenance) and the bases for the values. Please provide:*

(a) *the list of preinitiators considered in the initial screening along with their screening value(s);*

Basic Event	Probability	Description	Source
OCB4160H1Y	1.00E-04	4160 volt AC bus A1 breaker maintenance error	Screening Procedure
OCB4160H2Y	1.00E-04	4160 volt AC bus A2 breaker maintenance error	Screening Procedure
OCB4160H3Y	1.00E-04	4160 volt AC bus A3/A5 breaker maintenance error	Screening Procedure
OCB4160H4Y	1.00E-04	4160 volt AC bus A4 breaker maintenance error	Screening Procedure
OCB4160H5Y	1.00E-04	4160 volt AC bus A6 breaker maintenance error	Screening Procedure
OSM169AXXY	1.00E-04	Operator fails to turn AC breaker fast transfer switch on	Screening Procedure
OTKN2BNKAY	1.00E-02	Failure to restore N_2 bank A after maintenance	Screening Procedure
OTKN2BNKBY	1.00E-02	Failure to restore N_2 bank B after maintenance	Screening Procedure
OTKN2TRLRY	1.00E-02	Failure to restore nitrogen trailer after maintenance	Screening Procedure
OVHTESTVLY	3.00E-03	Operator fails to align SLC valves to proper config.	Screening Procedure
OVHTSTMAIY	3.00E-03	Operator fails to realign FWXT valves following test or maintenance	Screening Procedure

(b) *provide the basis for these value(s);*

The basis for these values was derived from WASH 1400, the IDCOR IPEM Methodology, and NUREG/CR 1278.

(c) *explain whether all preinitiators that were considered in the initial quantification were retained as events on the fault or the event trees throughout the analysis or some were dropped after the initial quantification. For those dropped, provide the basis for not considering them throughout the analysis.*

These preinitiators, along with their initial screening values, were retained in the fault trees through the subsequent quantifications.

13. *It is not clear from the submittal how dependencies associated with preinitiator human errors were addressed and treated. There are several ways by which dependencies can be treated. For example, in the restoration of several valves, a bolt is required to be "tightened." It is judged that if the operator fails to "tighten" the bolt on the first valve, he will subsequently fail on the remaining valves. In this example, the probability of the subsequent human events is influenced by the probability of the first event. This type of dependency is typically incorporated in the HRA by adjusting the HEPs for subsequent valve adjustments to reflect this dependence. In another example, poor lighting can result in increasing the likelihood of unrelated human events; that is, the poor lighting condition can affect different operators' abilities to properly calibrate or to properly restore a component to service, although these events are governed by different procedures and performed by different personnel. This type of dependency is typically incorporated in the HRA model by "grouping" the components so they fail simultaneously. In the third example, pressure sensor x and y may be calibrated using different procedures. However, if the procedures are poorly written, miscalibration is likely on both sensor x and y. This type of dependency is typically incorporated in the HRA model by adjusting each individual HEP in the IPE model representing calibration of the pressure sensors to reflect the quality of the procedures. Please provide a concise discussion and examples illustrating how dependencies were addressed and treated in the preinitiator HRA.*

Dependencies between pre-initiators were considered, and a dependency was found in the pre-initiator error ACB4160H3Y 4160 Volt A3/A5 maintenance error.

Common cause among all of the 4160 buses is captured in the 4160V bus maintenance error basic events ACB4160H1Y, ...H2Y, ...H3Y, ...H4Y, and ...H5Y. These basic events capture potential maintenance errors committed while performing breaker preventative maintenance during each refueling outage, which can prevent proper breaker operation (open or close on demand).

The rationale for the application of the basic events is based on breaker design and the way the maintenance is performed. The first fact is that maintenance on the A side buses (A1, A3, and A5) is performed at one time in the outage and maintenance on the B side (A2, A4, and A6) is performed days or even weeks later.

The second fact is that the breaker maintenance procedure is broken up into separate checklists for the 350 MVA breakers on buses A1 and A2, and the 250 MVA breakers of A3, A4, A5, and A6. These two combine the breakers into 4 groups: A1, A2, A3 and A5, and A4 and A6.

The third fact is that unit auxiliary and startup transformer power supply feeder breakers ACB A403 and A404 were replaced during RFO #8 with vacuum type circuit breakers. Therefore, the breakers on bus A4 are of a different type than A6, requiring different maintenance procedures and a separate human error basic event

14. *A numerical screening method was used in order to determine the most important human events. When this is done, it is important that the screening HEP values used are appropriately high (e.g. 0.1 - 0.5 for postinitiator human events) for all accident scenarios to ensure that important human events and important sequences are not truncated. In the Pilgrim IPE, however, some of the screening values used are on the order of 1E-3 or less. Such values are usually used as "nominal" values in PRAs rather than "screening" values. The use of low screening values can have the effect of distorting the screening analysis results in terms of the important human events and important accident sequences. In addition, it is not clear whether these screening values were modified to account for dependencies associated with the accident progression influences on human performance pertinent to the applicable accident sequences. For each postinitiator human event for which its screening value was retained throughout the analysis:*

(a) *Provide the basis for determining its assigned screening value;*

The screening values for all postinitiator Human Reliability Assessments (HRAs) were derived from WASH-1400, IDCOR Methodology, and NUREG/CR-1278. Two typical human actions were assessed :

1) Repair and recovery of systems that fail or are unavailable during a transient.

2) Actions that are taken by the operator in response to a transient that are specified by the EOPs and the satellite procedures.

Only those postinitiator HRAs which appeared in cutsets were identified as candidates for detailed HRA and were analyzed using the Technique for Human Error Rate Prediction (THERP) (NUREG/CR-1278). The remaining postinitiator human events retained their screening values used throughout the analysis. The values assigned to these events (e.g., failure to initiate suppression pool cooling) are consistent with the industry average range of values. The PNPS PRA was quantified at a truncation level of 1E-09. This level is low enough to provide assurance that all significant HRAs were assessed. Furthermore, the results of a sensitivity study show that all risk significant postinitiator human events were reviewed using the THERP methodology. Therefore, there is high confidence that all potentially risk significant human actions were reviewed.

(b) *Explain what was done to assure that important human actions were not eliminated from the analysis and important sequences were not truncated by using low HEP screening values.*

The combination of model quantification at a very low truncation level and the use of industry accepted ranges of human error rates provides high confidence that all important human actions/sequences were assessed. As described above, industry accepted values and methods were used for assigning HEP values. The computer model was quantified at 1.0E-09, a very low truncation level.

(c) *Explain how dependencies were dealt assuring that the screening values used were appropriate for each pertinent accident sequence in which that human event was modeled, so that important accident sequences (and hence, important insights regarding these actions) were not missed.*

All dominant cutsets were reviewed for accuracy and completeness. All pertinent human elements of these cutsets were reviewed with all other components of that cutset and any dependencies were reviewed and incorporated at that time.

There were no cases where a postinitiator human event having a screened value appeared in different types of accident scenarios. Any postinitiator human events contributing to more than one type of scenario (e.g., fail to depressurize appears in small LOCA as well as TQUX type of scenarios) has a detailed HRA. Thus, the screening values were appropriate for each pertinent accident sequence.

15. *It is not clear from the submittal how time "available" (i.e., the length of time from the moment there is an indication that an action should be performed until the action is completed) and time "required" (i.e., the time needed to perform the action) were calculated for the various postinitiator human events. For the events: 1) operator fails to crosstie feedwater; 2) operator fails to locally open LPCI injection valves; and 3) operator fails to depressurize:*

(a) *Provide the time "available" and the time "required" to perform each task.*

1) The time available to crosstie firewater is approximately 35 minutes. The time required to do the task is approximately 10-15 minutes.
2) The time available to locally open LPCI injection valves is approximately 35 minutes. The time required to do the task is about 10 minutes
3) The time available to depressurize is approximately 30 to 40 minutes The time required to do the task is less than a minute.

(b) *Explain what was the basis for estimating the time "available."*

Both operator actions dealing with the low pressure injection systems are credited only in transient conditions. They do not appear in LOCA initiated sequences. Thus, these actions would be required after depressurization. As the time available for depressurization is 30-40 minutes (from a generic GE report, NEDO-24708A "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors"), it follows that the time required for the low pressure injection systems would be the same.

(c) *Explain how differences in time "available" for a given action performed under different accident sequences were taken into consideration.*

Human action items 1 and 2 only appear under transient initiators, thus there would be no difference in time available for their functions. There is less time available for depressurization for ATWS cases than non-ATWS. Accordingly, the performance shaping factors for the ATWS were increased, resulting in a higher failure rate.

(d) *Explain how the time needed for operators to perform actions in parallel with other actions was taken into consideration when estimating the time "available."*

These three actions would be required within the same time period following a transient initiating event. However, in no sequences were they required simultaneously. They would not be done concurrently as a different set of mutually exclusive failure conditions would be required for each action. Thus, these actions would not be done in parallel. Following a transient, depressurization is required only if high pressure makeup is unavailable. Subsequently, Fire Water Crosstie would be required if the normal low pressure injection systems were unavailable. Manual opening of the RHR injection valves would be needed only if there was no AC power to the valves.

(e) *Explain how time "required" was estimated (for example, through simulator exercises or walkdowns).*

Operator Training and Requalification Training provide the basis for the time required to perform the firewater crosstie and depressurization maneuvers. The basis for manually opening the RHR injection valves in the field is based on engineering judgment and the results of surveillance tests.

16. *It is not clear how diagnostic error was handled in the HRA. In some actions (for example, operator fails to follow crosstie procedure), diagnostic error is handled as an error of omission in the procedure and a value from THERP Table 20-7 is used. In other actions (for example, operator fails to align direct torus vent), diagnostic is handled according to THERP guidance of "Diagnosis of Abnormal Event" (Chapter 12) and Table 20-3 is used. Please explain why diagnostic error in some instances is treated as error of omission to perform a step in a procedure.*

Human actions are typically required due to an unexpected or abnormal event. The first step in our HRAs was to determine how the operators would recognize the need for performing an action. In some cases, distinct annunciation is provided for an operator to perform an action within so much time. For example, the operator has time to perform the action before the situation occurs for which the result of his action will be needed. In other cases, such as fire water crosstie and aligning direct torus vent, no distinct annunciation is provided. The operators are guided by the EOPs. In these cases, credit can be taken for following the prescribed actions.

The human action for aligning direct torus vent was re-analyzed using an error of commission to perform a step in a procedure as its diagnostic error. There was no change in the resultant HRA value as this HRA is dominated by failing to perform the procedure (See Figure A1-3 of 1992 Submittal).

Specifically, firewater crosstie is an alternate low pressure injection system which can be used to maintain reactor water level above the top of active fuel. A low level alarm is associated with [illegible] inches reactor water level. No such alarm is associated with the top of active fuel, -16[illegible] inches. Emergency Operating Procedure EOP1 provides the direction to line this system up and to utilize it when needed. Thus, the operator diagnoses the need to use firewater based upon following a procedure, namely EOP1.

17. *We note that the IPE assumes that the operators 90% of the time will not follow the procedures directing them to trip the main feedwater given loss of DC control power (IPE Appendix A1-14). Please explain your rationale for the operators not following procedures with such a high probability.*

One of the insights obtained from the IPE analysis was the dependency of feedwater on DC power because of the operating procedures. When the IPE was performed, station procedures required that on a loss of the "A" DC bus the corresponding feed pumps must be secured and the breakers on the affected buses be tripped for electrical safety considerations. However, if the "B" DC bus is subsequently lost, the loss of "B" DC procedure instructs the operator to strip off the loads associated with that bus, independent of the status of the "A" bus. If both DC buses are deenergized, the operators receive alarms which alert them to the fact that HPCI and RCIC are unavailable, as are the SRVs for manual depressurization. The operator is faced with a dilemma. The procedure instructs him to secure the remaining operable feed pumps, but he knows he has no other high pressure injection systems and no SRVs with which to depressurize the vessel. Knowing this, it was believed that he would not secure the only injection source he has available.

This insight was transmitted to station management during the IPE process. Since the IPE was published, both of the loss of DC bus procedures have been revised to give the operator the opportunity to leave a feed pump running if both 125 volt DC buses are lost. The Loss of Essential DC bus procedures now contain cautions which alert the Senior Licensed Operators to the possibility of the loss of multiple feed systems after the loss of one or more essential DC buses. Therefore, there is no longer a concern with the operators being placed in a position where they must disregard approved procedures.

18. *The unavailability of the firewater system due to operator failure to crosstie is 0.017. This means that there is a high probability that the operator will successfully perform this action. This alignment, however, requires installation of a spool piece which is a rather complicated action; also the conditions under which the operator will perform this action are extreme. Furthermore, firewater is a non-safety grade system, and hence, pertinent procedures are not part of the EOPs and the operator may not be trained routinely for this action. Therefore, it appears that the value of 0.017 is rather optimistic for this specific action. Please provide the basis justifying that the value of 0.017 for firewater unavailability due to crosstie is reasonable.*

The value quoted in the question for FWXT unavailability is a combination of operator error and system component failures. It was derived by quantifying the FWXT system fault tree with no failures in the support systems.

In answering this question, each of the question's assumptions will be addressed. First, the installation of the spool piece is a fairly simple procedure. It is described in PNPS Procedure 5.3.26 "RPV Injection During Emergencies". To install the spool piece, the operator must remove it from the cabinet immediately adjacent to its installation point. Then he removes the couplings and blank flanges from the pipe ends, inserts the spool piece and strainer between the pipe ends and clamps it into place with the couplings. The spool piece is now installed. The operators are trained to perform this action during initial license training via job performance measures. They are also subject to periodic retraining on this action as part of the licensed operator requalification training program. Therefore, they are routinely trained on this procedure.

The assumption that the system is not safety grade and not included in the EOPs is incorrect. Procedure 5.3.26 "RPV Injection During Emergencies" is an EOP satellite procedure and is subject to the same level of administrative controls as the EOPs. The location where the operator will be performing this action is outside the secondary containment and is accessible without a secondary containment entry.

The stress levels experienced by the operators are factored into the detailed Human Error Probability calculation documented on pages A1-17 and 18 of the IPE report. Therefore, since approximately half of the system unavailability is derived from the human error probability for failure to line up FWXT for injection, the value for fire water crosstie unavailability is reasonable.

19. *It is not clear from the submittal how multiple-action dependencies were addressed and treated in the postinitiator HRA. The performance of the operator is both dependent on the accident under progression and the past performance of the operator during the accident of concern. For example, in the ATWS Event Tree discussion (Appendix C, page C.5-7) a number of interdependent multiple-actions are discussed. Improper treatment of human action dependencies may result in the elimination of potentially dominant accident sequences, and therefore, the identification of significant human events. Please provide a concise discussion and examples illustrating how multiple-action dependencies were addressed and treated in the postinitiator HRA. The discussion should address the two points below:*

(a) *Human events are modeled in the fault trees as basic events, such as failure to manually actuate. The probability of the operator to perform this function is dependent on the accident in progression - what symptoms are occurring, what other activities are being performed (successfully and unsuccessfully), etc. When the sequences are quantified, this basic event can appear, not only in different sequences, but in different combinations with different systems failures. In addition, the basic event can potentially be multiplied by other human events when the sequences are quantified, which should be evaluated for dependent effects. The quantification of the human events in the fault trees needs to consider these dependencies.*

The only cutsets having more than one human action were long term scenarios such as containment failure due to the loss of containment heat removal. Short term sequences such as ATWS do not typically credit more than one operator action. ATWS sequences specifically credit only one operator action, e.g., if SLC is not injected, no credit is taken for any other operator action. Additionally, any HRA dependence within the ATWS event trees was considered in the TRACG runs performed by General Electric.

Long term scenarios do contain various combinations of human errors. However, for the most part they are required at different times and do not present themselves as having any dependence on one another. For example, there are a few sequences where failure of the containment occurs due to the combined failure to use the normal venting path and the direct torus vent. While these items serve the same function, they are two totally separate actions from a dependency standpoint. The normal vent via the standby gas trains would be used early on in the sequence when pressure is between 2 and 30 psig, rather than later when pressure is challenging containment, (56 psig).

(b) *Human events are modeled in the event trees as top events. The probability of the operator to perform this function is still dependent on the accident progression. The quantification of the human events needs to consider the different sequences and the other human events.*

The quantification of human errors did consider the different sequences and other events where appropriate. For example, failure to depressurize for ATWS cases is different than for non-ATWS ones. There is less time for the operator to perform this function in an ATWS and therefore it was quantified differently.

20. *Conflicting probability values are given for operator failure to depressurize during non-ATWS scenarios. On page B.4-3 of the submittal, a probability of 2.74E-3 is given, while at Table A.1-1 a probability of 9.35E-4 is given. Please explain this apparent discrepancy.*

The probability for failure to depressurize during non-ATWS scenarios was calculated first to be 2.74E-3 and included in Appendix B. Subsequently, the value was recalculated based on more feedback from simulator exercises to be 9.35E-4. The latter value was used for all subsequent quantification. Unfortunately, Appendix B had already been prepared prior to the decision to go with the new value.

21. *The operator action to inhibit ADS under ATWS conditions has been found to be a significant human event in many PRAs. Please discuss the basis for your assumption that "The ADS system is always assumed to be inhibited by the operator upon the first actuation (reactor water level @ -49 inches) of either ADS timer," which implies that the IPE took 100% credit for the operator performing this action successfully.*

During the PNPS Safety Enhancement Program, BECo contracted with General Electric to perform TRACG runs in order to gain detailed, plant specific knowledge of how the plant would react during ATWS sequences. The results of this analysis showed that uncontrolled injection with low pressure systems due to ADS system actuation will not result in substantial fuel damage or threaten the integrity of the reactor vessel (see page C.5-7 of the IPE report).

These results were carefully weighed against the other events included in the ATWS event trees. If this event were included, neither branch would lead directly to core damage, and it would nearly double the number of event sequences to be analyzed. BECo determined that including this event would unnecessarily complicate an already complex event tree. As a result of this thought process, the operators are assumed to successfully inhibit ADS. This decision was a simplifying assumption eliminating an event tree node which would not affect core damage frequency.

22. *The back-end analysis (Section 4.5) took credit for three operator actions: (1) event OPER301, operator fails to initiate the drywell sprays prior to RPV failure (page 4.5-13); (2) event OPER501(N) operator fails to initiate drywell sprays when required (page 4.5-19 & 20); and (3) event OPER801, operator fails to initiate the drywell or RPV venting (page 4.5-26). These actions, however, are not discussed in the HRA portion of the submittal, and therefore, it is not clear how the associated HEPs were estimated; please explain.*

The back end analysis was performed in two sections, the Containment Sequence Event Trees (CSET) analysis and the Containment Phenomenology Event Tree (CPET) analysis. In the CSET analysis, operator actions for initiating drywell sprays and for failing to initiate containment venting are included in the fault trees for the Drywell Sprays and Containment Heat Removal top events. The results of the CSET are a set of Plant Damage States (PDS). Each of these damage states is a unique set of system availabilities based on the progression the reader follows through the tree. The probability value associated with each PDS is determined by system availability and the value associated with the CSET HRAs.

The basic events mentioned above were used as flags, with values of either 1 or 0, appropriate to the conditions within the vessel and the primary containment for each Plant Damage State. These conditions vary from one plant damage state to another and are included in the three CPET events mentioned above. During the quantification of the CPETs, the values associated with these events were used as indications of whether that action was assumed to be successful in this Plant Damage State.

23. *Explain why the operation of the drywell sprays was not considered in determining the release categories.*

While the operation of drywell sprays was not listed in section 4.7.1 in the list of "containment sequence characteristics selected for use in defining release categories", the operation of drywell sprays is included in the containment assessment and source term analysis. This list was intended to show those characteristics which have the greatest bearing on the efficient binning of unique release categories in the PNPS source term analysis.

The operation of drywell sprays was included in the source term analysis in the construction of the CSETs. The operation of drywell sprays was included in these trees and is a factor in determining the Plant Damage State(s) into which each accident sequence can be assigned. See figure 4.3-3 'Plant Damage State Grouping Diagram" for a graphic view of how the operation of drywell sprays determines the release categories.

These CSETs serve as input to the CPETs which analyze each plant damage state to determine the probability for release in each of the release categories. So while the use of containment sprays is not included in the list in section 4.7.1, the presence or absence of drywell sprays influence the plant damage states, and therefore the release categories into which the release from each accident sequence will result.

24. *Explain how the probability of the wetwell failure was accounted for in the analysis, especially at or near the time of reactor pressure vessel failure.*

As described in section 4.5.1, the two Pilgrim CPETs are provided in figures 4.5-1 and 4.5-2. In each of these trees, wetwell failure was accounted for in the top event "NO_WW: Wetwell Vapor Space Failure or Venting". This top event is described in section 4.5.8.1 which references the detailed containment failure analysis contained in section 4.4 of the report. The results of this analysis, as cited in section 4.5.8.1, show that the median containment failure pressure is 98 psig. At the median containment failure pressure, 64% of the total containment failure probability is due to wetwell failure and 36% is due to drywell head failure.

As detailed in section 4.4.1, the containment overpressure capacity analysis provided a fragility curve which represents the probability of containment failure as a function of containment pressure and depicts the contribution of each critical failure mode to the failure probability. This curve is shown as figure 4.4-1.

The CPETs include an event for "Drywell Failure at RPV Failure", and this event includes considerations for "alpha" mode in-vessel steam explosion, drywell failure as a result of pedestal structural failure, and drywell liner melt through in addition to drywell overpressurization. Since the wetwell is not subject to any of these other failure modes which result from vessel failure, the analysis done for PNPS contains no extra considerations for wetwell failure "at or near the time of reactor pressure vessel failure".

25. *The overall risk profile appears to be dominated by the containment flooding - drywell/RPV venting. However, there is not adequate discussion in the submittal of these events.*

(a) *Provide a discussion regarding containment flooding - drywell/RPV venting strategy. Include in the discussion the automatic and manual actions to be taken, and the relative timing of significant events in sequences involving containment flooding (e.g., relative times of core damage, vessel breach, initiation of containment flooding, and RPV venting).*

The progression of events which lead to the containment flooding-drywell /RPV venting strategy are best illustrated by following the progression of an accident through the PNPS EOPs. The containment flooding actions are specified in the Pilgrim EOPs.

Non-ATWS Sequences

For non-ATWS sequences, the operators would enter EOP-01. Within EOP-01, as water level dropped below the entry condition, the operators would be directed to verify all automatic isolations, ECCS initiations, and emergency diesel generator initiation. The operators would be directed to maintain water level between +9" and +48" with the systems listed in EOP-01 Table A: Condensate/Feedwater, CRD, RCIC, HPCI, Core Spray, or LPCI. If these systems cannot maintain RPV water level within the specified band, the operator is also allowed to use the systems listed in EOP-01 Table B: SSW crosstied to the RHR system, the Fire Water Crosstie to RHR, ECCS keep full system, demineralized water transfer crosstied to SLC, and Condensate Transfer crosstied to ECCS. The operator is also told to inhibit ADS initiation when water level falls below the ADS initiation water level.

If the operator is unable to maintain RPV water level above the top of active fuel (TAF), the operator is directed to line up the systems listed in EOP-01 Table C : Condensate, RHR A and B, and Core Spray A and B for injection, start the pumps, and maximize injection flow. If these systems cannot be lined up for injection with at least one pump running, the operator is directed to line up Table B systems in an attempt to get at least one pump running in one injection system. When the reactor water level reaches TAF, if any source of injection is lined up with one pump running the operator is directed to open all four SRVs and depressurize the RPV. If the operator cannot line up any injection source with one pump running, steam cooling is required, and the operator is allowed to let water level decrease to -165" before opening all four SRVs.

Regardless of the RPV pressure at the beginning of the sequence, when RPV pressure is below 125 psig, all possible injection sources are lined up with pumps running, and RPV water level still cannot be restored and maintained above TAF, the primary containment flooding is required. The operator exits the level control portion of EOP-01 and enters EOP-09 'Primary Containment Flooding".

ATWS sequences

For ATWS sequences, the operators would enter EOP-02. They would be directed to verify all automatic isolations, ECCS initiations, and emergency diesel generator initiation. The operators are then directed to inhibit ADS. If primary containment integrity is threatened by reactor power above 3% or indeterminate, and torus water temperature is above the Boron Injection Initiation Temperature (BIIT), and one or more SRVs are open or drywell pressure is above 2.5 psig, and RPV water level is above TAF, then the operator is directed to secure injection except for boron injection and CRD, and allow water level to lower until any one of the conditions described above clears and primary containment is no longer threatened.

If containment integrity is not being threatened, the operators are instructed to maintain RPV water level above TAF. If they cannot maintain RPV water level above TAF, they are to maintain water level above -155 inches. When water level cannot be maintained above -155 the operators are directed to depressurize the RPV by opening the SRVs. They are also directed to stop injection into the RPV from all sources except for CRD, SLC, and RCIC, in order to prevent the uncontrolled injection of large amounts of unborated water into the RPV causing power excursions. The operators can resume injection into the RPV when RPV pressure falls below the Minimum Alternate RPV Flooding Pressure for the number of SRVs the operator has been able to open. If RPV level cannot be restored and maintained above -155 inches, then primary containment flooding is required. The operator exits the level control portion of EOP-01 and enters EOP-09 'Primary Containment Flooding".

Primary Containment Flooding

The operator will use EOP-09 to restore adequate core cooling via core submergence when actions to submerge the core via injection into the RPV have not been successful. The operator is directed to operate the following systems to fill the primary containment and establish adequate core cooling via two methods. The operator can inject into the vessel using Condensate/Feedwater, CRD, RCIC (with suction from the CST only) or Core Spray (with one train lined up from the CST). The operator is also directed to inject into the primary containment using SSW crosstied to RHR, ECCS keep fill, Condensate Transfer crosstied to ECCS as a source of water, and by using the torus cooling, torus spray, or drywell spray headers to deliver the water to the containment.

The operators fill the containment until water level reaches 11 feet, the point at which the lowest portion of the recirculation system is beginning to be covered. Above this elevation, water might flow into the RPV through a break in the system. The operator is then told to vent the RPV through the MSIVs, main steam line drains, HPCI steam line, or RCIC steam line. This is necessary in order to allow water from the drywell to flow into the RPV through the break or rupture in the primary system. When the primary containment water level reaches 68 feet, the water level inside the RPV is at the top of the active fuel. At this point the operator is told to secure the RPV vent and maintain containment water level between 68 feet and 77 feet (the elevation of the drywell vent).

Relative Timing of Containment Flooding Events

The MAAP computer code was used to model the response of PNPS to severe accident conditions. A number of accident sequences were run using this code and some of these sequences included containment flooding and RPV venting. The following table lists the sequences and the timing of key events in these sequences.

MAAP Sequence number	Core Uncover Time (hr)	Core Melt Time (hr)	Vessel Failure Time (hr)	Initiation of Containment Flooding (hr)	Containment Vent Time (hr)	RPV Vent Time (hr)
ATWS02B	0.24	2.3	4.58	1.53	.88	6.57
ATWS03	0.63	1.51	6.72	0.7	N/A	11.0
ATWS05	0.63	1.53	6.7	0.7	N/A	9.61
ATWS05A	0.63	1.55	6.71	0.7	N/A	12.7
SL01	0.37	1.34	3.07	3.16	17.9	6.99
TQUX03	0.56	1.71	4.01	4.1	4.12	6.64
TQUX04	0.56	1.71	3.96	4.1	16.9	7.8
TQUX06	0.6	2.96	6.8	6.9	18.8	10.4
TQUX07	0.59	2.94	6.77	6.8	N/A	12.00
TQUX08	0.56	1.71	3.96	4.1	4.1	7.32
TQUX09	0.56	1.7	4.79	3.1	4.9	7.48
TWQUV01	37.4	41.9	50.4	50.5	N/A	54.3
TWQUV01A	37.4	41.9	50.4	50.6	N/A	56.9

(b) *Explain why this strategy is classified as a "late" containment failure.*

As defined in the IPE in section 4.7.1.3 "Time of Containment Failure", Late Failure sequences are those sequences where containment failure occurs many hours after vessel failure. They are also those sequences in which containment failure occurs many hours after reactor shutdown, as in the case of loss of decay heat removal.

(c) *How was the possibility of human error considered in evaluating the success of this strategy in the CPET?*

As was explained in question 22 above, the human error events used in the CPETs were used as flags to indicate whether or not drywell spray and drywell/torus venting were successful in the Plant Damage State being quantified.

The sensitivity of the level 2 analysis to the success of this strategy was dealt with in IPE section 4.8.1.8 'Sensitivity to Containment Flooding and Drywell/RPV Venting" as follows:

'Sensitivity case 9A was performed to assess the impact of late containment flooding and venting. A review of all dominant core damage sequences indicated that PDSs 9, 10, 22, 23 and 25 were dominated by sequences where the ability and the procedural requirements for containment flooding and drywell/RPV venting were met. For sensitivity case 9 containment flooding and drywell/RPV venting were "turned off" for these PDSs.

Figures 4.8-36 through 4.8-38 show the results of this sensitivity case. With containment flooding and drywell/RPV venting removed, the fraction of sequences with no containment failure (or venting) increased from the base case value of 17.0% to 40.6%. The fraction of sequences with drywell failure or drywell or RPV venting decreased from 78.2% in the base case to 27.8%. Wetwell failures or venting increased from 4.5% to 30.9%. Hence, timing and mode of containment failure are strongly sensitive to containment flooding and venting procedures.

26. *Identify any functional sequences that exceed the reporting criteria of Generic Letter 88-20, Appendix 2.*

The PNPS IPE submittal reported all functional sequences regardless of their frequency.

Those sequences in Table 3.4-1, which have a core damage frequency greater than 1E-6, exceed reporting criterion 1.

Those sequences in Table 3.4-1, which are greater than 5% of total core damage frequency, exceed reporting criterion 2.

Criterion 3 asks BECo to report any functional sequence that has a core damage frequency greater than or equal to 1E-6 per year and that leads to containment failure which can result in a radioactive release magnitude greater than or equal to the BWR-3 or PWR-4 release categories of WASH-1400. Due to the method used to perform the source term analysis, individual accident sequences cannot be tracked to determine if they lead to containment failure greater than the BWR-3 release category of WASH-1400.

In the PNPS IPE, the core damage sequences are evaluated in a two step process to determine the source term release timing and magnitude. First, individual accident sequences are evaluated by the Containment Systems Event Trees (CSETs) to determine the post core damage and post containment failure status of important systems. The output of these CSETs are a set of Plant Damage States (PDS) with probabilities associated with them. These PDS are then evaluated by the Containment Phenomenological Event Trees (CPETs) and the results are source term Release Categories and probabilities.

Section 4.7.3.2 of the PNPS IPE summarizes the way radioactive releases were categorized. Releases were categorized as High, Medium, Low, Low-Low and Negligible. The High category was defined as those releases which contain more than 10% of the total core inventory of Cesium and Iodine. This matches the BWR-3 release category listed in Table 5-1 "Summary of Accidents Involving Core" from the Executive Summary of WASH-1400.

Because all of the core damage sequences are evaluated by the CSETs and a number of different core damage sequences could be combined together in a single PDS, a single accident sequence cannot be traced through to a release category with a source term greater than the BWR-3 release category. However, Table 4.7-5 "Release Term Magnitudes" lists those "High" Release Categories with a source term greater than the BWR-3 release category. In spite of this, Pilgrim was able to gain a number of insights into the relationship between core damage and containment release. These are summarized in Section 5.0 of the report.

Those class V sequences in Table 3.4-1 which have a core damage frequency greater than 1E-7 exceed reporting criterion 4.

27. *It is not clear in the submittal if plant changes due to the station blackout rule were credited in the analysis. Please provide the following: (1) identify whether plant changes (e.g., procedures for load shedding, alternate AC power) made in response to the blackout rule were credited in the IPE and what are the specific plant changes that were credited; (2) if available, identify the total impact of these plant changes to the total plant core damage frequency and to the station blackout CDF (i.e., reduction in total plant CDF and station blackout CDF); (3) if available, identify the impact of each individual plant change to the total plant core damage frequency and to the station blackout CDF (i.e., reduction in total plant CDF and station blackout CDF); (4) identify any other changes to the plant that have been implemented or planned to be implemented that are separate from those in response to the station blackout rule, that reduce the station blackout CDF; (5) identify whether the changes in #4 are implemented or planned; (6) identify whether credit was taken for the changes in #4 in the IPE; and (7) if available, identify the impact of the changes in #4 to the station blackout CDF.*

BECo's response to the station blackout rule was contained in BECo letter 89-057. This letter listed the modifications which BECo committed to install to comply with the station blackout rule. When this letter was written, the SBO diesel generator and its associated non 1E bus A8 had been installed. The additional modifications not yet installed included pull-to-lock switches on the 4Kv breakers for the RHR pumps, Core Spray pumps, and the shutdown transformer feeder breakers. It also included installing switches to initiate the load shedding logic on AC power trains A and B.

When the IPE was performed, it included the SBO diesel and bus A8, but did not include the pull-to-lock and load shedding switches. This was reflected in the HRA analysis performed for the Operator Failing to Align the Blackout Diesel Generator. No sensitivity study was done to assess their impact on core damage frequency. No sensitivity study was performed which would have assessed the impact of the SBO diesel generator on core damage frequency. As has been shown above, the contribution to core damage frequency from Station Blackout sequences is small (approximately 3%) so any change in core damage frequency due to the inclusion of these modifications would be minimal.

As stated in section 3.1.1 of the report, the IPE included an additional transient initiator category for loss of offsite power to account for the fifteen instances at Pilgrim in which the plant lost offsite power from the 345 Kv source but retained availability of the 23 Kv offsite source. Because this event has occurred several times at Pilgrim and because of the dependencies of front-line systems to this initiator, the IPE developed and quantified separate event trees to model plant response to this initiator. Ten of these fifteen instances involved only two causes:

1. Salt buildup, causing flashover (6 of 15)

2. Lightning strikes (4 of 15)

Due to the high frequency of the loss of the 345 Kv source, modifications were made during RFO #7 (1987) to:

1) reduce the likelihood of salt buildup/flashovers by applying a special coating to the insulators in the switch yard; and

2) reduce the effect of lightning strikes through phase separation.

The effects of these modifications were included in the initiating event frequency for loss of offsite power and are discussed in section 3.1.1 of the report. Also, see the answers to questions 3 and 5 above for additional discussion on the impact of these modifications.

Additionally, during 1994 and 1995 outages we completed a switchyard betterment program. We have not taken credit for these modifications in the station blackout CDF.

JDK/nas/Rap95/nrcipeqs