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September 19, 2005

AEP:NRC:5811-04
10 CFR 50.90

Docket Nos: 50-315
50-316

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Stop O-P1-17
Washington, DC 20555-0001

Subject: Donald C. Cook Nuclear Plant Units 1 and 2
Docket Nos. 50-315 and 50-316
Updated Information Regarding License Amendment Request to Extend the Allowed Outage Time for the Emergency Diesel Generators (TAC Nos. MC4525 and MC4526)

References:

1) Letter from J. N. Jensen, Indiana Michigan Power Company (I&M), to U. S. Nuclear Regulatory Commission (NRC) Document Control Desk, "Donald C. Cook Nuclear Plant Units 1 and 2 - Docket Nos. 50-315 and 50-316 - Extension of Allowed Outage Times for Emergency Diesel Generators, 69 kV Offsite Power Circuit, Component Cooling Water, and Essential Service Water," AEP:NRC:4811, dated September 21, 2004 (ML042780478).

2) Letter from D. P. Fadel, I&M, to NRC Document Control Desk, "Response to Request For Additional Information Regarding License Amendment Request to Extend the Allowed Outage Times for Emergency Diesel Generators, 69 kV Offsite Power Circuit, Component Cooling Water, and Essential Service Water (TAC Nos. MC4525 and MC4526)," AEP:NRC:5811-01, dated April 7, 2005 (ML051020239).

3) Letter from J. N. Jensen, I&M, to NRC Document Control Desk, "Partial Response to Request For Additional Information Regarding License Amendment Request to Extend the Allowed Outage Times for Emergency Diesel Generators, 69 kV Offsite Power Circuit, Component Cooling Water, and Essential Service Water (TAC Nos. MC4525 and MC4526)," AEP:NRC:5811, dated March 18, 2005 (ML050890319).

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4) Letter from J. N. Jensen, I&M, to NRC Document Control Desk, "Remainder of Response to Request For Additional Information Regarding License Amendment Request to Extend the Allowed Outage Times for Emergency Diesel Generators, 69 kV Offsite Power Circuit, Component Cooling Water, and Essential Service Water (TAC Nos. MC4525 and MC4526)," AEP:NRC:5811-02, dated May 6, 2005 (ML051380429).

Dear Sir or Madam:

By Reference 1, as modified by Reference 2, Indiana Michigan Power Company (I&M) proposed to amend Facility Operating Licenses DPR-58 and DPR-74 for Donald C. Cook Nuclear Plant, Units 1 and 2. I&M proposed changing the Technical Specifications to permit extending the allowed outage time (AOT) from 72 hours to 14 days for an inoperable emergency diesel generator (EDG), and proposed adding a license condition allowing a one-time extension of the AOT for the alternate offsite power (69 kilovolt) supply from 72 hours to 14 days. The proposed EDG AOT extension was supported by a plant modification to install supplemental diesel generators that will provide an additional source of electrical power. Reference 3 transmitted a partial response to a Nuclear Regulatory Commission (NRC) request for additional information (RAI) regarding the proposed amendment. Reference 4 transmitted the remainder of the response to the NRC RAI. This letter updates risk related information transmitted by Reference 4.

Enclosure 1 to this letter provides an affirmation pertaining to the statements made in this correspondence. Enclosure 2 provides updated risk related information transmitted by Reference 3.

Enclosure 2 to the original amendment request transmitted by Reference 1 included an evaluation of significant hazard considerations performed in accordance with 10 CFR 50.92 and an environmental assessment performed in accordance with 10 CFR 51.22. The information in this letter provides supporting information for the amendment request submitted by Reference 1. The information provided in this letter does not alter the validity of the original evaluation of significant hazard considerations for the remaining proposed changes. The environmental assessment provided in Enclosure 2 to Reference 1 also remains valid.

This letter contains no new regulatory commitments. Should you have any questions, please contact Mr. John A. Zwolinski, Safety Assurance Director, at (269) 466-2428.

Sincerely,

J. N. Jensen
Site Vice President

JRW/rdw

Enclosures:

1. Affirmation.
2. Updated Risk Additional Information Regarding License Amendment Request To Extend Allowed Outage Time

c: J. L. Caldwell, NRC Region III
K. D. Curry, Ft. Wayne AEP, w/o enclosures
J. T. King, MPSC
MDEQ – WHMD/RPMWS
NRC Resident Inspector
D. W. Spaulding, NRC Washington, DC

Enclosure 1 to AEP:NRC:5811-04

## AFFIRMATION

I, Joseph N. Jensen, being duly sworn, state that I am Site Vice President of Indiana Michigan Power Company (I&M), that I am authorized to sign and file this letter with the Nuclear Regulatory Commission on behalf of I&M, and that the statements made and the matters set forth herein pertaining to I&M are true and correct to the best of my knowledge, information, and belief.

Indiana Michigan Power Company

Joseph N. Jensen
Site Vice President

SWORN TO AND SUBSCRIBED BEFORE ME

THIS 19th DAY OF September, 2005

Regan D. Wendzel
Notary Public

REGAN D. WENDZEL
Notary Public, Berrien County, MI
My Commission Expires My Commission Expires Jan. 21, 2009

# UPDATED RISK INFORMATION REGARDING LICENSE AMENDMENT REQUEST TO EXTEND ALLOWED OUTAGE TIME

References for this enclosure are provided on Page 15 and Page 16.

By Reference 1, as modified by Reference 2, Indiana Michigan Power Company (I&M) proposed to amend Facility Operating Licenses DPR-58 and DPR-74 for Donald C. Cook Nuclear Plant (CNP), Units 1 and 2. I&M proposed changing the Technical Specifications to permit extending the allowed outage time (AOT) from 72 hours to 14 days for an inoperable emergency diesel generator (EDG), and proposed adding a license condition allowing a one-time extension of the AOT for the alternate offsite power (69 kilovolt) supply from 72 hours to 14 days. The proposed EDG AOT extension was supported by a plant modification to install supplemental diesel generators (SDGs) that will provide an additional source of electrical power if offsite power was lost and the remaining EDG became inoperable (i.e., a station black out or "SBO"). Reference 3 transmitted a partial response to a Nuclear Regulatory Commission (NRC) request for additional information (RAI) regarding the risk evaluations for the proposed amendment. Reference 4 transmitted the remainder of the response to the NRC RAI.

In Reference 4, I&M indicated that the strategy for using the SDGs to respond to such an event would be to restore power to components needed for reactor coolant pump (RCP) seal injection within 13 minutes, thereby preventing seal damage. I&M also stated that the human reliability analysis (HRA) was based on an early draft of the Operations procedure for responding to a loss of offsite power and loss of the remaining EDG. Since the procedure was not finalized, I&M stated that a human error probability (HEP) of 0.05 was used as an upper bound to estimate the risk profiles. I&M also stated that the methodology shown in Reference 4 was applicable to the HRA that would be performed to determine a final HEP once the procedure was finalized.

Simulator trials of draft operating procedures indicate that restoration of RCP seal injection within 13 minutes could be accomplished, but present a challenge to operating crews. Based on information contained in NRC Information Notice 2005-14 (Reference 5), I&M elected to modify its strategy such that the SDGs would be used to restore power to components needed for injecting coolant into the reactor coolant system (RCS) loops within 30 minutes after the loss of power. RCS loop injection would provide the makeup needed for plant cooldown and depressurization, while also providing the makeup needed for an RCP seal leak. I&M elected not to structure the procedures to attempt restoration of seal injection prior to restoration of loop injection, since restoration of loop injection would provide a much more likely success path.

As stated in NRC Information Notice 2005-14, the assumed maximum RCP seal leak rate resulting from the absence of seal injection flow may be assumed to be 21 gallons per minute per pump. Simulator trials indicate that this strategy is less challenging than the previous strategy of restoring seal injection within 13 minutes. This strategy is similar to that used at Seabrook Station in support of an approved amendment (Reference 6) extending its EDG AOT.

The change in strategy was discussed with members of the NRC Staff in a telephone discussion, conducted on July 28, 2005. In that discussion, it was determined that I&M would provide the following information.

NRC Requested Information Item 1

*Updated information on the operator action to utilize the SDGs. If the same HRA methodology is used, then the detailed HRA need not be submitted. The information should include: (a) the estimated human error probability (HEP) for the operator action; (b) a discussion of the key procedural steps; (c) a discussion of how dependency of this operator action to other operator actions was assessed, if different than already submitted; and (d) a sensitivity of CDF to changes in the HEP.*

I&M Response to Requested Information Item 1(a)

As was done in the HRA described in Reference 4, the HRA for the operator actions to implement the new strategy uses the EPRI cause-based decision tree methodology (Reference 7) and the Techniques for Human Error Rate Prediction methodology described in NUREG/CR 1278 (Reference 8) to develop the HEP. The resultant value for the HEP is 0.021. Although I&M anticipates no further changes in the strategy for using the SDGs to mitigate an SBO, the procedural details for implementing this strategy have not been finalized. Therefore, a bounding HEP value of 0.05 has been assumed as indicated in the risk evaluations described in this enclosure.

I&M Response to Requested Information Item 1(b)

The use of the SDGs to respond to an SBO would involve the following operator actions. (Attachment 1 to Reference 4 provides a one-line diagram of the affected portions of the CNP electrical system.)

Following confirmation that the SDGs have automatically started and energized 4 kilovolt Bus 1 (normally powered from the 69 kilovolt alternate offsite circuit), control room operators would perform the following:

- Consistent with the current Westinghouse Emergency Response Guidelines for restoration of charging flow following an SBO, an operator would be dispatched to locally isolate the seal injection flow path.

- In parallel with the local operator actions:

  Control room operators would energize a safety bus from 4 kilovolt Bus 1.

Control room operators would manually start one essential service water (ESW) pump and one component cooling water pump.

Control room operators would verify proper alignment of the coolant charging pump (CCP) suction and discharge paths for RCS loop injection.

- Control room operators would start the CCP after the local operator reports the seal injection is isolated. This would initiate RCS loop injection.

I&M Response to Requested Information Item 1(c)

Since the human failure event (HFE) consisting of a failure to provide RCS injection within 30 minutes remains first in the SBO scenario, it does not depend on any other HFEs and will always occur as an independent HFE. In addition, the dependency analysis described in the Reference 4 response to NRC Question 3.b for HFEs subsequent to this HFE remains valid as there has been no change in the chronological order of these HFEs.

I&M Response to Requested Information Item 1(d)

The importance measures related to core damage frequency (CDF) for the HEP are shown in the following table for the current probabilistic risk assessment (PRA) modeling approach as well as the previous modeling approach described in Reference 4. The importance measures provided in Reference 4 were calculated for SDGs aligned to bus T11C/D. Consistent with NRC Requested Information Item 4, importance measures for the current modeling approach were calculated for SDGs aligned to bus T11A/B. However, the importance measures would be similar regardless of the bus to which the SDGs are aligned. As this table shows, the Fussell-Vesely (F-V) and risk achievement worth (RAW) values for the HEP have not significantly changed from their values provided in Reference 4.

| HEP Importance Measures Related to CDF | | | | |
|---|---|---|---|---|
| Case | New Strategy, SDGs aligned to T11A/B | | Previous Strategy, SDGs aligned to T11C/D | |
| | F-V | RAW | F-V | RAW |
| Unit 1 New Base Case:<br><br>- SDG function unavailable 3 days per year for T&M.<br>- Each EDG unavailable 8 days per year for T&M.<br>- All other components T&M set to average yearly values.<br>- SDGs assigned EDG failure data.<br>- Bounding HEP of 0.05. | 0.048 | 1.9 | 0.047 | 1.9 |

| HEP Importance Measures Related to CDF | | | | |
|---|---|---|---|---|
| Case | New Strategy, SDGs aligned to T11A/B | | Previous Strategy, SDGs aligned to T11C/D | |
| | F-V | RAW | F-V | RAW |
| Unit 1 New Base Case:<br><br>- EDG 1CD out of service.<br>- SDG and EDG T&M unavailabilities set to zero.<br>- All other components T&M set to average yearly values.<br>- Bounding HEP of 0.05. | 0.16 | 4.1 | 0.17 | 4.2 |

T&M = test and maintenance

The sensitivity of the CDF to changes in the HEP is shown in the table below. Cases are shown for a bounding HEP of 0.050 and for the best-estimate HEP of 0.021 identified in the response to Requested Information Item 1(a).

| Sensitivity of CDF to HEP | | |
|---|---|---|
| Case | **CDF for Bounding HEP of 0.050** | **CDF for Best-Estimate HEP of 0.021** |
| Unit 1 New Base Case:<br><br>- SDGs aligned to T11A/B.<br>- SDG function unavailable 3 days per year for T&M.<br>- Each EDG unavailable 8 days per year for T&M.<br>- All other components T&M set to average yearly values.<br>- SDG assigned generic failure data. | 2.53E-5 | 2.46E-5 |
| Unit 1 New Base Case:<br><br>- SDGs aligned to T11A/B.<br>- EDG 1CD assumed out-of-service.<br>- SDGs and other EDGs assumed available.<br>- All other components T&M set to average yearly values.<br>- SDG assigned generic failure data. | 5.55E-5 | 4.99E-5 |

| Sensitivity of CDF to HEP | | |
|---|---|---|
| Case | **CDF for Bounding HEP of 0.050** | **CDF for Best-Estimate HEP of 0.021** |
| Unit 2 New Base Case:<br><br>- SDGs aligned to T21C/D.<br>- SDG function unavailable 3 days per year for T&M.<br>- Each EDG unavailable 8 days per year for T&M.<br>- All other components T&M set to average yearly values.<br>- SDG assigned generic failure data. | 2.53E-5 | 2.46E-5 |
| Unit 2 New Base Case:<br><br>- SDGs aligned to T21C/D;<br>- EDG 2AB assumed out-of-service.<br>- SDGs and other EDGs assumed available.<br>- All other components T&M set to average yearly values.<br>- SDG assigned generic failure data. | 5.73E-5 | 5.18E-5 |

<u>NRC Requested Information Item 2</u>

*A discussion of how the SDGs will be used in the event of an SBO.*

<u>I&M Response Requested Information Item 2</u>

I&M's strategy for using the SDGs in the event of an SBO has changed from that described in Reference 4. Instead of restoring RCP seal injection within 13 minutes, the operators would now isolate RCP seal injection and restore RCS loop injection within 30 minutes. This change in strategy is based on additional NRC guidance (Reference 5) regarding RCP seal modeling under loss of seal cooling conditions, as well as providing assurance that the necessary operator actions could be accomplished within the specified time. The new strategy is reflected in the following scenario description.

Upon a sustained loss of power on 4 kilovolt Bus 1, both SDGs will start automatically. The power operated disconnect switch will automatically open to isolate 4 kilovolt Bus 1 from the 69 kilovolt/4 kilovolt transformer. Upon attaining rated speed and voltage, and confirming the power operated disconnect is open, the SDGs would automatically synchronize with each other and the SDGs' output circuit breakers would automatically close onto the de-energized 4 kilovolt Bus 1. The two diesel generators, when connected to the bus, will be capable of parallel operation.

The applicable emergency operating procedure, will direct the operators to confirm that 4 kilovolt Bus 1 is energized. Following confirmation that 4 kilovolt Bus 1 is energized, the operators will perform the steps described in the I&M response NRC Requested Information Item 1.

Event trees and fault trees in the PRA model were modified to reflect the change from the previous strategy to the new strategy. As described in Reference 4, the model had previously been changed to explicitly represent the SDGs in the event trees by adding top event EP to represent the operability of the SDGs. With the time interval for operator actions being changed from 13 minutes to 30 minutes, the sequences in the event trees following the EP success branch were assumed to have the following timeline:

- Operators are dispatched to locally isolate RCP seal injection.
- Both SDGs start automatically and are manually loaded onto the 4 kilovolt safety buses.
- RCS injection is manually restored.

In the above scenario, RCP seal loss of coolant accidents (LOCAs) are not prevented, but a large percentage of seal leakage events have flow rates that are low enough to be mitigated through the use of a single CCP with no containment spray actuation. The remainder of the events are assumed to have large enough flow rates to resemble a small break LOCA. Therefore, in the events trees, these events progress like a normal small break LOCA. Sequences following the EP failure branch progress like a normal SBO.

Two event trees were created for the RCP seal LOCAs with lower flow rates. One event tree (TLEPL) was created for EP success following a single-unit loss of offsite power event and one event tree (TLEPD) was created for EP success following a dual-unit loss of offsite power event. In these event trees, the RCP seal LOCA flow rates are low enough that sufficient RCS injection would be provided by a single charging pump with no containment spray actuation and no need to switch to recirculation during the sequence.

The event trees for a single-unit loss of offsite power and a dual-unit loss of offsite power were changed to account for the success criterion for the EP top event. A new top event (LKS) for RCP seal LOCA flow was added. The LKS success branch transfers to the TLEPL or TLEPD event tree, as appropriate. The LKS failure branch transfers to the small break LOCA event tree appropriate for single-unit or dual-unit loss of offsite power events.

A fault tree was created to represent the effects of the various RCP seal LOCA flow rates that could occur following a complete loss of RCP seal cooling. A basic event was created to represent the probability of an RCP seal LOCA having a large enough flow rate to resemble a small LOCA. Eleven percent of the events were assumed to have high enough flow rates to resemble a small LOCA.

The Unit 1 and Unit 2 high pressure injection fault trees were changed to include the possibility that the safety injection (SI) pump could be used to provide RCS inventory make-up if the CCP

fails following the power recovery using the SDGs. The credit for the SI pump was limited to cases involving SDG success. A basic event was created for the probability of an operator error to start the SI pump after a charging pump failure. This operator error probability was assumed to be a conservatively high value.

The SDGs were assumed to be unavailable due to T&M for 3 days per year. The EDGs were assumed to be unavailable due to T&M for 8 days per year. EDG generic failure data were used for SDG failures to run and failures to start.

NRC Requested Information Item 3

*A statement that the change in approach (i.e., RCS injection instead of seal injection) will not significantly change the risk profile (dominant accident sequences), provided this is the case. If not, provide the dominant accident sequences and revised uncertainty analysis as was done in the response to RAIs 4 and 5 [in Reference 4].*

I&M Response Requested Information Item 3

The tables below show the Unit 1 sequences with frequencies that contribute greater than 4 percent to total CDF or large early release frequency (LERF) for the new strategy or the previous strategy assumed in Reference 4. Both cases shown in the tables assume a bounding HEP value of 0.05, with SDG failure data assumed to be the same as EDG failure data. The Unit 2 results are similar.

As indicated in the tables, the two strategies have the same dominant sequences with the same sequence frequencies. For CDF, the percentage contributions are the same. For LERF, the slight difference in percentage contributions is attributable to the differences in LERF between the two strategies. Specifically, the LERF for the base case using the current modeling approach is slightly lower than the LERF for a similar base case using the previous modeling approach. Therefore, the change in strategy (i.e., RCS injection instead of seal injection) does not significantly change the risk profile.

| Event Tree Sequence Contributions to CDF | | | | |
|---|---|---|---|---|
| Sequence Identifier | Sequence CDF | Percentage Contribution to CDF (New Strategy) | Percentage Contribution to CDF (Previous Strategy) | Sequence Description |
| SLO-S08 | 1.40E-6 | 5.5 | 5.5 | Small LOCA with recirculation failure |
| SLO-S16 | 1.28E-6 | 5.0 | 5.0 | Small LOCA with recirculation failure and containment spray recirculation failure |
| TRA-S39 | 1.17E-6 | 4.5 | 4.5 | Transient with failure of auxiliary and main feed, operator failure to bleed and feed, failure of containment spray, and failure of igniters |
| ESW4S39 | 1.03E-6 | 4.0 | 4.0 | Loss of all ESW with failure to recover ESW |

| Event Tree Sequence Contributions to LERF | | | | |
|---|---|---|---|---|
| Sequence Identifier | Sequence LERF | Percentage Contribution to LERF (New Strategy) | Percentage Contribution to LERF (Previous Strategy) | Sequence Description |
| TRA-S40 | 4.65E-7 | 10.6 | 10.3 | Transient with failure of auxiliary and main feed, operator failure to bleed and feed, failure of containment spray, failure of hydrogen igniters, and large early release from containment |
| ISL1S08 | 3.87E-7 | 8.9 | 8.5 | Interfacing systems LOCA (failure in RHR cooldown suction line) occurs with failure of operators to isolate the break |
| SGR1S20 | 3.05E-7 | 7.0 | 6.7 | SG tube rupture in RCS Loop 1, faulted SG overfills, one or more safety or relief valves sticks open, and failure of 100°F/hr cooldown |
| SGR2S20 | 3.05E-7 | 7.0 | 6.7 | SG tube rupture in RCS Loop 2, faulted SG overfills, one or more safety or relief valves sticks open, and failure of 100°F/hr cooldown |
| SGR3S20 | 3.05E-7 | 7.0 | 6.7 | SG tube rupture in RCS Loop 3, faulted SG overfills, one or more safety or relief valves sticks open, and failure of 100°F/hr cooldown |

| Event Tree Sequence Contributions to LERF | | | | |
|---|---|---|---|---|
| Sequence Identifier | Sequence LERF | Percentage Contribution to LERF (New Strategy) | Percentage Contribution to LERF (Previous Strategy) | Sequence Description |
| SGR4S20 | 3.05E-7 | 7.0 | 6.7 | SG tube rupture in RCS Loop 4, faulted SG overfills, one or more safety or relief valves sticks open, and failure of 100°F/hr cooldown |

RHR = residual heat removal
SG = steam generator
°F/hr = degree Fahrenheit per hour

NRC Requested Information Item 4

*Revised Tables 2-1 and 2-2 from RAI response (may be abbreviated). What is desired is the CDF and LERF for Unit 1 and Unit 2 for the following cases: (a) Base Case; (b) interim base case (credit for SDG, with the current EDG AOT of 72 hours); and (c) the projected base case? For the projected base case, assume the SDGs are aligned to bus T11A/B for Unit 1 and to bus T21C/D for Unit 2.*

I&M Response Requested Information Item 4

The first and second tables below are revised and abbreviated versions of Reference 4 Tables 2-1 and 2-2, respectively. The three cases shown in these tables are defined as follows. The "current" base cases represent the base PRA model with the revisions described in Reference 1 and the enhancements described in Reference 4.

The "projected" base cases start from the current base case, but allow the SDGs to be credited. The SDGs are assumed to be unavailable 3 days per year due to T&M. The projected base cases also include an adjustment of the average unavailability of each EDG, from the 1.35 days per year assumed in the current base cases, to 8 days per year to represent the expected movement of EDG maintenance activities online from outage periods. In addition, the projected cases include the revised modeling that represents the intended use of the SDGs to mitigate rather than prevent an RCP seal leak. The projected cases represent the expected "new" base case when the SDGs have been implemented.

The "interim" base cases also start from the current base case, allow the SDGs to be credited, and assume that the SDGs are unavailable for 3 days per year. For these cases, the average unavailability of each EDG is kept at an average value of 1.35 days per year. The interim cases also include the revised modeling that represents the intended use of the SDGs to mitigate rather than prevent an RCP seal leak. The interim base cases assume the SDGs have been installed,

procedures have been changed to provide direction for their use, operator training has been conducted, etc., but there has been no change in the EDG maintenance practices.

The first table compares the current base case CDF and LERF values with projected base case values. The second table compares the interim base case CDF and LERF values with the projected base case values. All of the values in the tables for the projected and interim cases assume a bounding HEP value of 0.05.

The first table shows that the addition of the SDGs and the extension of the EDG AOT will lead to a significant decrease in risk for the plant relative to its current condition. Section 2.2.4 of Regulatory Guide (RG) 1.174 (Reference 9) states that, if it can clearly be shown that the proposed change will result in a decrease in CDF or a decrease in LERF, the change will be considered to have satisfied the relevant principle of risk-informed regulation with respect to CDF or LERF. The second table shows that the extension of the EDG AOT would lead to a relatively small increase in plant risk compared with its interim state.

| Comparison of Unit 1 and Unit 2 "Projected" Base Cases with "Current" Base Cases | | | | |
|---|---|---|---|---|
| Case Definition | CDF | LERF | Delta CDF | Delta LERF |
| Unit 1 Current Base Case:<br><br>- No credit for SDGs.<br>- Each EDG unavailable 1.35 days per year for T&M.<br>- All other components T&M set to average yearly values. | 4.15E-5 | 7.23E-6 | | |
| Unit 1 Projected Base Case with SDGs aligned to T11A/B:<br><br>- Current Base Case but with credit allowed for SDGs.<br>- SDG function unavailable 3 days per year for T&M.<br>- Each EDG unavailable 8 days per year for T&M.<br>- All other components T&M set to average yearly values.<br>- SDGs assigned EDG generic failure data. | 2.53E-5 | 4.36E-6 | -1.6E-5 | -2.9E-6 |
| Unit 2 Current Base Case:<br><br>- No credit for SDGs.<br>- Each EDG unavailable 1.35 days per year for T&M.<br>- All other components T&M set to average yearly values. | 4.14E-5 | 7.20E-6 | | |
| Unit 2 Projected Base Case with SDGs aligned to T21C/D:<br><br>- Current Base Case but with credit allowed for SDGs.<br>- SDG function unavailable 3 days per year for T&M.<br>- Each EDG unavailable 8 days per year for T&M.<br>- All other components T&M set to average yearly values.<br>- SDG assigned EDG generic failure data. | 2.53E-5 | 4.34E-6 | -1.6E-5 | -2.9E-6 |

| Comparison of Unit 1 and Unit 2 "Projected" Base Cases with "Current" Base Cases | | | | |
|---|---|---|---|---|
| Case Definition | CDF | LERF | Delta CDF | Delta LERF |
| Unit 1 Interim Base Case with SDGs aligned to T11A/B:<br><br>- SDG function unavailable 3 days per year for T&M.<br>- Each EDG unavailable 1.35 days per year for T&M.<br>- All other components T&M set to average yearly values.<br>- SDG assigned generic EDG failure data. | 2.42E-5 | 4.21E-6 | | |
| Unit 1 New Base Case with SDGs aligned to T11A/B:<br><br>- SDG function unavailable 3 days per year for T&M.<br>- Each EDG unavailable 8 days per year for T&M.<br>- All other components T&M set to average yearly values.<br>- SDG assigned generic EDG failure data. | 2.53E-5 | 4.36E-6 | 1.1E-6 | 1.5E-7 |
| Unit 2 Interim Base Case with SDGs aligned to T21C/D:<br><br>- SDG function unavailable 3 days per year for T&M.<br>- Each EDG unavailable 1.35 days per year for T&M.<br>- All other components T&M set to average yearly values.<br>- SDG assigned generic EDG failure data. | 2.42E-5 | 4.19E-6 | | |
| Unit 2 New Base Case with SDGs aligned to T21C/D:<br><br>- SDG function unavailable 3 days per year for T&M.<br>- Each EDG unavailable 8 days per year for T&M.<br>- All other components T&M set to average yearly values.<br>- SDG assigned generic EDG failure data. | 2.53E-5 | 4.34E-6 | 1.1E-6 | 1.5E-7 |

<u>NRC Requested Information Item 5</u>

*Revised Table 2-5 from the RAI response, except that the Unit 1 case of the SDG aligned to bus T11C/D need not be included.*

I&M Response Requested Information Item 5

The two tables below show the values for incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP), for the "Projected" base cases with EDGs out of service. The first table is an abbreviated version of Table 2-5 from the Reference 4, and is based on a bounding HEP value of 0.050. The second table is based on a best-estimate HEP value of 0.021 identified in the response to Requested Information Item 1(a), and includes only the limiting case for each unit from the first table.

As stated in Section 2.4 of RG 1.177 Reference 10, an ICCDP of less than 5.0E-7 is considered small, and an ICLERP of 5.0E-8 or less is considered small. As shown in the first table below, the largest ICCDP (1.23E-6) and the largest ICLERP (1.71E-7), which are based on a bounding HEP of 0.050, are above the NRC acceptance guidelines. As shown in the second table below, the largest ICCDP (1.04E-6) and largest ICLERP (1.37E-7), which are based on a best-estimate HEP of 0.021, are above the NRC acceptance guidelines.

However, Section 2.4 of RG 1.177 also states that the acceptance guidelines should not be interpreted as being overly prescriptive and that uncertainties associated with PRA calculations preclude a definitive decision with respect to acceptance based purely on numerical results. Section 2.4 also states that the decision must be based on a full understanding of the contributors to the PRA results and the impacts of the uncertainties, both those that are explicitly accounted for in the results and those that are not.

Accordingly, the following conservatisms, which were not explicitly quantified in the results, should be considered:

- No credit is taken for the 69 kilovolt switchyard as a potential source of available power.
- No credit is taken for the operating SDG if one SDG fails.
- No credit is taken for the later use of the SDGs if the operators fail to align the SDGs and restore RCS injection within the first 30 minutes.
- No credit is taken for the opposite, unaffected unit's capability to provide RCS make-up through the charging pump cross-tie to the affected unit during a single-unit SBO.

Additionally, the configuration risk impacts in the tables below were determined without consideration of compensatory measures that could be performed to manage the risk to lower values.

Therefore, the configuration risk impacts for EDG outages are considered to satisfy the risk guidance provided in RG 1.177.

| Comparison of Unit 1 and Unit 2 EDG Outages with "Projected" Base Cases With Bounding HEP (0.050) | | | | | |
|---|---|---|---|---|---|
| SDGs aligned to | EDG Out of Service | CDF | LERF | ICCDP Based on Projected Base Case & 14 Day AOT | ICLERP Based On Projected Base Case & 14 Day AOT |
| T11A/B | 1AB | 5.51E-5 | 8.82E-6 | 1.14E-6 | 1.71E-7 |
| | 1CD | 5.55E-5 | 8.77E-6 | 1.16E-6 | 1.69E-7 |
| | 2AB | 2.50E-5 | 4.25E-6 | -1.46E-8 | -4.10E-9 |
| | 2CD | 2.49E-5 | 4.25E-6 | -1.57E-8 | -4.33E-9 |
| T21C/D | 1AB | 2.50E-5 | 4.23E-6 | -1.07E-8 | -3.91E-9 |
| | 1CD | 2.50E-5 | 4.23E-6 | -1.27E-8 | -3.99E-9 |
| | 2AB | 5.73E-5 | 8.69E-6 | 1.23E-6 | 1.67E-7 |
| | 2CD | 5.57E-5 | 8.75E-6 | 1.17E-6 | 1.69E-7 |

| Comparison of Unit 1 and Unit 2 EDG Outages with "Projected" Base Cases With Best-Estimate HEP (0.021) | | | | | |
|---|---|---|---|---|---|
| SDGs aligned to | EDG Out of Service | CDF | LERF | ICCDP Based on Projected Base Case & 14 Day AOT | ICLERP Based On Projected Base Case & 14 Day AOT |
| T11A/B | 1CD | 4.99E-5 | 7.82E-6 | 9.69E-7 | 1.37E-7 |
| T21C/D | 2AB | 5.18E-5 | 7.75E-6 | 1.04E-6 | 1.35E-7 |

NRC Requested Information Item 6

*Discussion that the previously submitted information is still valid, except as modified in the new submittal. Specifically: (1) does the 69kV bus risk assessment change? (2) are the seismic, fire, flooding and "other" external events risk assessments still valid?*

I&M Response Requested Information Item 6

Except as modified in this letter, the previously submitted risk information (References 1, 3, and 4) is still valid based on the following considerations.

The risk calculations performed in support of the 69 kilovolt switchyard AOT and documented in Reference 4 were not affected by the changes described in this letter. Those calculations were based entirely on the current base cases, which did not credit any aspect of the plant modification related to the SDGs.

As was done in the previously submitted risk evaluations (References 1, 3, and 4), the risk evaluations performed to recognize the change in strategy and documented in this letter are based on the following external event assumptions:

The SDGs were credited in the PRA model only for an SBO event; and

No internal flooding events, fire events, or seismic events were postulated.

As a result, the SDGs were not credited with mitigating or causing any seismic, fire, flooding, or "other" external event.

References for this Enclosure

1. Letter from J. N. Jensen, I&M, to NRC Document Control Desk, "Donald C. Cook Nuclear Plant Units 1 and 2 - Docket Nos. 50-315 and 50-316 - Extension of Allowed Outage Times for Emergency Diesel Generators, 69 kV Offsite Power Circuit, Component Cooling Water, and Essential Service Water," AEP:NRC:4811, dated September 21, 2004 (ML042780478).

2. Letter from D. P. Fadel, I&M, to NRC Document Control Desk, "Response to Request For Additional Information Regarding License Amendment Request to Extend the Allowed Outage Times for Emergency Diesel Generators, 69 kV Offsite Power Circuit, Component Cooling Water, and Essential Service Water (TAC Nos. MC4525 and MC4526)," AEP:NRC:5811-01, dated April 7, 2005 (ML051020239).

3. Letter from J. N. Jensen, I&M, to NRC Document Control Desk, "Partial Response to Request For Additional Information Regarding License Amendment Request to Extend the Allowed Outage Times for Emergency Diesel Generators, 69 kV Offsite Power Circuit, Component Cooling Water, and Essential Service Water (TAC Nos. MC4525 and MC4526)," AEP:NRC:5811, dated March 18, 2005 (ML050890319).

4. Letter from J. N. Jensen, I&M, to NRC Document Control Desk, "Remainder of Response to Request For Additional Information Regarding License Amendment Request to Extend the

Allowed Outage Times for Emergency Diesel Generators, 69 kV Offsite Power Circuit, Component Cooling Water, and Essential Service Water (TAC Nos. MC4525 and MC4526)," AEP:NRC:5811-02, dated May 6, 2005 (ML051380429).

5. NRC Information Notice 2005-14, "Fire Protection Findings on Loss Of Seal Cooling to Westinghouse Reactor Coolant Pumps," dated June 1, 2005 (ML051080499).

6. Letter from S. P. Wall, NRC, to M. E. Warner, Florida Power and Light, "Seabrook Station, Unit No. 1 - Issuance of Amendment Re: Change to Emergency Power Systems (TAC No. MC0635)," dated September 21, 2004 (ML042240471).

7. EPRI document EPRI-TR-100529, "An Approach to the Analysis of Operator Actions in Probabilistic Risk Assessment," by G. W. Parry, et. al., dated June 1992.

8. NUREG/CR 1278, "Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications, Final Report," dated: August, 1983.

9. NRC RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions On Plant-Specific Changes to the Licensing Basis," Revision 1, dated November 2002.

10. NRC RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," dated August 1998.