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August 1, 1986

U. S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Washington, D. C. 20555

ATTENTION: Mr. Ashok C. Thadani, Director
PWR Project Directorate #8
Division of PWR Licensing-B

SUBJECT: Calvert Cliffs Nuclear Power Plant
Unit Nos. 1 & 2; Docket Nos. 50-317 & 50-318
Exigent Request for Amendment

Gentlemen:

The Baltimore Gas and Electric Company hereby requests an Amendment to its Operating License Nos. DPR-53 and DPR-69 for Calvert Cliffs Unit Nos. 1 & 2, respectively, with the submittal of the proposed changes to the Technical Specifications.

PROPOSED CHANGE (BG&E FCR 86-138)

Change pages 3/4 8-1 and 8-2 of the Unit 1 and 2 Technical Specifications as shown on the marked-up copies attached to this transmittal.

DISCUSSION

Problem Description

This change proposes to add a one-time extension to the allowed out-of-service period for No. 12 diesel generator such that maintenance can be effected without requiring an unscheduled cold shutdown. To adequately perform the worst-case repairs and allow for contingencies, we would need 10 days of outage time for the swing diesel generator.

We have discovered carbon monoxide (CO) in No. 12 diesel generator (DG) jacket cooling water. Subsequently, testing and investigations have been performed to determine the origin of the gas. We believe that the CO is from diesel engine exhaust/combustion products and not from cooling water additives or chemical reactions. There does not appear to be any gas in the air cooling water which might be carried over to the jacket cooling water. Currently, we have identified several possible sources for the CO. They are one or more of the following:

A001
3/36

Rec'd w/check $150.00

1. Turbocharger casting defect or corrosion;
2. Cylinder wall crack;
3. Cylinder liner seal leakage with accompanying exhaust belt leakage, or;
4. Cylinder liner adapter seal leakage.

Possibilities 2 and 4 appear to be most likely based on available information.

The diesel generator manufacturer has been consulted on the problem. They have stated that quantifying (in ppm) the amount of CO in the water would have no bearing on the problem. The manufacturer recommends that a water jacket pressure test/leak check be performed at 50 psi using a borescope. We would also use a dye. This test is the most plausible method available to determine which of the above possibilities is the actual problem.

We consider No. 12 DG to be fully operable. However, if the test results indicate repairs are in order, we would want to make the necessary repairs as soon as possible without causing a shutdown. We feel that these repairs, if they are required, would be needed immediately in order to prevent a potential catastrophic failure in the future. We would not want to reassemble the DG after doing the test if we found one of the problems mentioned previously. Furthermore, the longer we wait to perform the test and make repairs (if required), the more No. 12 DG will be subjected to test starts and other cycling that could be detrimental to its long term performance.

We are presently making preparations to perform the pressure test/leak check and we would like to pursue and correct the potential problem in a timely manner. However, without performing this test, we cannot determine whether repairs will be necessary and if they are, what the duration of the maintenance will be. We estimate that the worst-case repairs could take ten days when accounting for contingencies. This worst-case problem is a cylinder wall crack.

We are submitting this proposed change to the Technical Specifications now to allow enough time to completely repair the DG should the most time consuming maintenance be required. We request a reply by August 15, 1986. We wish to perform the pressure test on August 18, 1986.

It should be noted that there are no out-of-specification operating parameters which indicate the diesel generator can not perform its intended function. The temperature changes across the engine along with the cooling water levels and pressure remain satisfactory. Only the need to vent the jacket cooling water heat exchanger after diesel generator operation is a departure from normal practice.

Qualitative Analysis

We have provided in the next section our assessment of the change in plant risk during a 10-day period in which No. 12 diesel generator is unavailable. The results of this analysis show that there is no significant change in overall plant core melt frequency during a single 10-day outage. We believe that this conclusion is to be expected.

On a loss of offsite power, No. 12 DG starts, but only automatically aligns to a specific unit when a LOCA occurs and a Safety Injection Actuation Signal (SIAS) is initiated. If there is loss of offsite power (LOSP) without a LOCA, the operators are instructed to line-up No. 12 DG to a specific unit. The Interim Reliability Evaluation Program (IREP), which analyzed only a single unit at Calvert Cliffs, indicates via the calculated unavailabilities that there is a probability of 5×10^{-2} (P_1) that the operator will fail to align No. 12 DG to Unit 1 and that there is an overall probability of 1.2×10^{-1} (P_2) that No. 12 DG will not be available to provide power to Unit 1 because it is needed on Unit 2. Additionally, the probability that it will fail to start and run during the demand period is about 7×10^{-2} (P_3).

Unavailability of No. 12 DG = $P_1 + P_2 + P_3$

The net result is that the probability of No. 12 DG failing to take a role in mitigating the consequences of an offsite power event, as modeled in IREP, is about 2.4×10^{-1} (24% or 1 in 4). Clearly, because of this high unavailability assumed for the swing diesel generator, the contribution of its failure to overall core melt frequency is very small. This tends to reinforce our confidence in the accuracy of the very small calculated change seen between our model results and those obtained from IREP.

RISK ANALYSIS

Assumptions, Initial Conditions, and Limitations

Our analysis is concerned with the likelihood that in the 10-day period during which No. 12 DG is unavailable there will be a LOSP event which will result in a total loss of plant AC power, and could initiate a series of events leading to core damage.

The offsite circuits feeding the plant are:

- Two 500 kv feeds from the BG&E system, and
- 69 kv feed from the PEPCO system via the Southern Maryland Electric Cooperative (SMECO) system.

In the event that a total LOSP were to occur, two available onsite AC power sources remain:

- No. 11 DG for Unit 1 via 4 kv Bus 11
- No. 21 DG for Unit 2 via 4 kv Bus 24

A single DG is capable of supplying all necessary shutdown loads for a Unit. Additionally, either of the plant DGs will provide the necessary power input to the battery systems to ensure that DC power is maintained to both units during the LOSP. There are two events of concern:

- LOSP
- LOCA, following a loss of offsite power

A LOSP, from IREP, is estimated to occur with an annual frequency of 0.14. Current data for the industry (NSAC-103) indicates that this is probably a significant over-estimate of the actual LOSP frequency. The probability of a non-recoverable LOCA following a LOSP is conservatively assessed to be 2×10^{-3}.

We have assumed that a LOSP leads to a loss of heat sink and that in turn leads to Reactor Coolant System (RCS) high pressure, when a PORV cannot open. The pressurizer safety valve then opens and fails to close. The probabilities used for these events are from IREP.

We believe a loss of all offsite AC power sources to be unlikely. Because of the redundancy and physical separation of the offsite sources, there is good reason to believe that a simultaneous failure would not occur. This conclusion is based on the following reasoning.

As a result of their different sources, a common failure would only occur during:

- o widespread transmission system disturbances involving the simultaneous failure of both BG&E and PEPCO systems, or

- o An extremely severe meteorological event, such as a tornado, severe hurricane, or ice storm, which causes a failure of all three power circuits.

A widespread transmission system failure resulting in a loss of BG&E and PEPCO system power has not occurred in the past 30 years. Therefore, the expected frequency is less than 0.03/year. With current system reserves, reliability criteria and protective equipment, it is felt that the true frequency is much lower. Therefore, this contribution is insignificant and will be disregarded.

Based on tornado frequency and proximity, we have calculated a frequency of tornado-induced failures equal to 8.2×10^{-4} tornado failures/year. This frequency is less than a normal LOSP and therefore contributes very little to risk and can be neglected.

Our FSAR estimates the expected total frequency of LOSP to be about 0.1 per year. This frequency is dominated by switchyard faults or other plant-centered events which have little or no warning associated with them. However, since these events are typically very short in duration, they do not contribute significantly to risk. A small contribution to this frequency is from severe hurricanes. Although these LOSP events are potentially of long duration, the actual risk posed by these events is small due to the advance warning associated with the approach of the storm. This warning allows for a controlled plant shutdown well in advance of any potential LOSP. The resultant reduction in core decay heat greatly mitigates the effect of a LOSP and provides more time for recovery.

No. 12 DG is not scheduled to be unavailable when there is any likelihood of an ice storm; therefore, this phenomenon does not contribute.

The events presented above are only a portion of possible events that were considered. Additional events are:

- o Floods,
- o Airplane crashes,
- o Fires,
- o Steam Line Breaks,
- o Large Break LOCA, etc.

These have all been examined and have been found to be insignificant. The small break LOCA bounds all of the above events.

Analytical Methodology

The references used in this analysis are:

Calvert Cliffs IREP Study,
Updated Calvert Cliffs FSAR, and
NSAC-103 (Losses of Offsite Power at U.S. Nuclear Power Plants - all years through 1985).

To analyze the conditional core melt frequency associated with a 10-day outage of No. 12 DG, a simplified plant model was developed to encompass all necessary front line systems and required dependencies which play a role in preventing core damage following a LOSP. The model used is shown in Figure 1.

This model presumes that No. 12 DG is out-of-service. Therefore, neither No. 12 DG nor the system trains which are dependent upon No. 12 DG are included. In this way, the model represents the actual plant configuration and requirements during the period that No. 12 DG is removed from service.

To simplify the analysis, the model was structured so that the primary mitigating systems (front line systems) could be treated as independent entities. The success of a front line system is defined as:

[Front line system success] = [system train successful] AND [system train dependencies successful]

In this way, relevant portions of the system can be represented as single blocks whose unavailability can be calculated from a separate system model.

The initiators included in the model are:

- o LOSP event
- o LOCA given a LOSP event

The model is solved using the "GO" methodology. "GO" is a computerized availability assessment code developed by the Electric Power Research Institute for the utility industry. This code is of particular value in evaluating plant models because it utilizes an "engineering approach" during the model development phase.

The sources of data for the individual components used in the model all come directly from the Calvert Cliffs IREP study. The various initiator frequencies come from different sources.

The frequency for a LOSP is from IREP. The probability of recovery from a LOSP within hours is computed from the frequencies provided in NSAC-103. The probability of a LOCA given a LOSP is computed using relief valve data from IREP.

The model contains the following sets of success criteria:

(1) Core damage is prevented if:

- o Core damage is prevented for Unit 1
  and
  Core damage is prevented for Unit 2

(2) Core damage is prevented for Unit 1 if:

- o A Unit 1 primary system energy transport path is successful
  and
  A Unit 1 secondary energy heat sink is available

Similarly for Unit 2, core damage is prevented if:

- o A Unit 2 primary system energy transport path is successful
  and
  A Unit 2 secondary energy heat sink is available

(3) For either Unit 1 or Unit 2, a primary system energy transport path is successful if:

- o There is no LOCA present
  or
- o The ECCS train (HPSI) is available

(4) For either Unit 1 or Unit 2 a secondary heat sink is available if:

- o There is no loss of main feedwater
  or
- o The auxiliary feedwater system and secondary steam relieving capability are available.

The remainder of the success criteria for the model reflect the hardware configurations within the plant, with a single exception, which is described below.

Each battery has the capability of providing the required DC loads for indication for approximately four hours. At the expiration of this period, if a DG is not available to supply power to the battery charger, a loss of DC is assumed to occur. There is, however, a high likelihood that offsite power will be recovered within four hours, so "recovery of offsite power" becomes an alternate success path, and therefore was quantified for the purposes of this model. The source of data for this recovery factor is NSAC-103.

As mentioned earlier, the frequency for a LOSP is 0.14. Current data for the industry (NSAC-103) indicates that this is probably an over-estimate of the actual LOSP frequency for Calvert Cliffs.

The frequency provided for a LOSP is only associated with the 500 kv feeds, so the use of the 69 kv SMECO tie can be considered a recovery action which affects the overall frequency of a LOSP. If the failures of the 500 kv feed and the SMECO tie line are considered independent of the LOSP frequency (where a LOSP of duration less than one hour is considered not to lead to a core damage sequence), the LOSP frequency can be quantified.

There is a procedure for establishing the 69 kv feed to the plant, and there is about one hour to implement the recovery action. Therefore, a failure to utilize the 69 kv is conservatively estimated to be 0.1 per 500 kv loss. That means that the LOSP frequency is equal to 0.14 x 0.1 = 0.014 per year.

This result provides the frequency used for our analysis.

Results

From the analysis described above, the probability of a core damage event during a 10-day period in which No. 12 DG is unavailable is 5.013×10^{-7}. This represents an upper bound on the expected frequency because throughout the analysis an attempt was made to treat assumptions on a bounding basis.

From IREP, the nominal probability of a LOSP event leading to core damage with No. 12 DG available during a 10-day period is calculated as shown below.

From IREP Table 8.2 (p. 8-73) there are four dominant sequences involving a LOSP.

SEQUENCE	SEQUENCE DESCRIPTOR	FREQUENCY
(1) T_1-81-65	(T_1Q-D"CC')	5.3×10^{-6}
(2) T_1-82	(T_1I)	4.9×10^{-6}
(3) Blackout	-	4.4×10^{-6}
(4) T_1-85	(T_1LCC')	1×10^{-6}

When calculated out, the total contribution to core melt (cm) frequency due to LOSP initiating events is 1.56×10^{-5}/year. For two units this approximates 3×10^{-5} cm/year. Over any 10-day period, this is equivalent to 8.3×10^{-7} cm/10 days.

Conclusions and Insights

We conclude that there is no significant change in core melt frequency associated with the unavailability of No. 12 DG on a one-time basis over a period of 10 days. The difference between 8.3×10^{-7} cm/10 days and 5.01×10^{-7} cm/10 days is negligible.

At first glance, the conclusion that having No. 12 DG unavailable for a period of 10 days does not significantly impact plant risk may seem surprising. This result can be rationalized quite easily.

(1) The probability of a loss of offsite power over the relatively short period of 10 days is very small.

(2) The probability of a coincident LOCA is even smaller.

This means that the likelihood of needing ECCS over a 10-day period is virtually negligible. It is only the need for ECCS that makes the 4 kv distribution necessary.

The event which dominates the risk is the need for auxiliary feedwater, which is AC independent. The cross coupling between two units of the DC supply to Auxiliary Feedwater (AFW) means that two batteries must fail before AFW fails (there is also a way of opening the valves without DC, which is not credited in this analysis). Therefore, the dominant concern is one of recovering power before the batteries are exhausted.

NSAC-103 shows that there is a very small likelihood of not recovering offsite power within four hours. Thus, the likelihood of an increase in frequency of a core damage event which is solely attributable to the unavailability of No. 12 DG is essentially negligible.

Mitigating Features

In addition to the risk analysis which showed that the unavailability of No. 12 DG for a 10-day period is not a significant hazards consideration, there are other mitigating features at Calvert Cliffs.

As discussed previously, BG&E has a unique 69 kv SMECO tie line. This power source is capable of handling all of the safe shutdown loads at the site (it has the load-carrying capacity of two diesel generators). In a recent safety evaluation report supporting license amendments for Units 1 and 2, the NRC approved the SMECO tie as a fully qualified GDC-17 power source. In addition to this feature, we will refrain from removing any offsite busses or circuits from service while No. 12 DG is unavailable. This will help prevent any events that could lead to a LOSP.

The reliability of the Calvert Cliffs DGs is outstanding, based on the results of an industry survey conducted by the EPRI Nuclear Safety Analysis Center in 1985. This survey evaluated the previous 100 consecutive DG tests. All three Calvert Cliffs DGs were found to be essentially 100 percent reliable from the perspective of preventing a station blackout. Our DGs have maintained this high level of reliability since the survey was performed.

Even in the unlikely event of a LOSP followed by a simultaneous failure of two of the three DGs at Calvert Cliffs, two full-capacity steam-driven AFW pumps would be available to maintain the "blacked-out" unit in a safe shutdown condition until either offsite or onsite power was restored. This redundancy in the AC-independent feedwater system exceeds that which is typically required by the NRC (a typical AFW system for a PWR with a C-E or Westinghouse NSSS is one motor-driven and one steam-driven pump, or two motor-driven and one steam-driven pump).

In the event of a loss of AC power at one of the two units at Calvert Cliffs, there are a number of important plant features and services which are shared between the two units. This commonality would allow the unit with an operable DG to support the more important safe shutdown functions of the other unit. Among the most notable of the features is the recently installed cross-connect between the Unit 1 and Unit 2 motor-driven AFW pumps. In the event of a station blackout at one unit <u>and</u> a subsequent failure of <u>both</u> steam-driven AFW pumps serving that unit, this cross-connect would provide a source of water from the unaffected unit's motor-driven pump.

The Calvert Cliffs DC electrical power system (including the batteries, the battery chargers, and the inverters) is common to Units 1 and 2. In the event that only a single DG remained operable following a LOSP (placing one unit in a station blackout condition), it would provide battery charging to a battery that serves both units. In this situation, neither unit would suffer a lack of battery capacity.

Calvert Cliffs Units 1 and 2 share a common control room. Even in the event that one of the remaining two DGs failed following a LOSP, the remaining DG would power the control room emergency ventilation system. Therefore, the control room would remain a mild environment from both an instrumentation and habitability standpoint during a station blackout at one of the two units.

We also utilize a detailed event based procedure that was developed by Combustion Engineering to address the LOSP/Natural Circulation event. This procedure provides specific guidance to the operator that "walks" him through various scenarios and alternate actions based on plant system status.

Besides the existing features at Calvert Cliffs which mitigate the chances of a LOSP, we are considering making procedural changes to further prevent such events. We will modify our severe weather/hurricane policy during the duration of the 10-day outage to add greater protection against LOSP events.

DETERMINATION OF SIGNIFICANT HAZARDS

This proposed change has been evaluated against the standards in 10 CFR 50.92 and has been determined to involve no significant hazards considerations, in that operation of the facility in accordance with the proposed amendment would not:

(i) involve a significant increase in the probability or consequences of an accident previously evaluated; or

This change, allowing a 10-day action statement for No. 12 DG on a one-time basis, does not significantly increase the probability or consequences of an accident previously evaluated. Due to the commonality of our plant design and the insignificant increase in risk, the probability of retaining AC power remains virtually the same during any 10-day outage of No. 12 DG.

(ii) create the possibility of a new or different type of accident from any accident previously evaluated; or

No new or different type of accident will be created by this proposed change. A LOSP and Station Blackout has been evaluated.

(iii) involve a significant reduction in a margin of safety.

This change does involve an incremental reduction in the margin of safety in that the swing DG is proposed to be removed from service for up to a 10-day period. However, this reduction is not considered significant in that a probabilistic risk assessment performed reveals only a negligible reduction in the margin of safety.

FEE DETERMINATION

Pursuant to 10 CFR 170.21, we are including BG&E Check No. (1906122) in the amount of $150.00 to the NRC to cover the application fee for this request.

Very truly yours,

JA Tiernan

STATE OF MARYLAND :
: **TO WIT:**
CITY OF BALTIMORE :

Joseph A. Tiernan, being duly sworn states that he is Vice President of the Baltimore Gas and Electric Company, a corporation of the State of Maryland; that he provides the foregoing response for the purposes therein set forth; that the statements made are true and correct to the best of his knowledge, information, and belief; and that he was authorized to provide the response on behalf of said Corporation.

WITNESS my Hand and Notarial Seal: Theresa Knapik
Notary Public

My Commission Expires: July 1, 1990

JAT/BEH/PAF/JES/dlm

Attachments

cc: D. A. Brune, Esquire
J. E. Silberg, Esquire
S. A. McNeil, NRC
T. Foley, NRC
T. Magette, DNR