June 8, 2009

Mr. Stewart B. Minahan
Chief Nuclear Officer, Vice President - Nuclear
Cooper Nuclear Station
Nebraska Public Power District
72676 648A Avenue
Brownville, NE 68321

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE COOPER NUCLEAR STATION LICENSE RENEWAL APPLICATION (TAC NO. MD9763 AND MD9737)

Dear Mr. Minahan:

By letter dated September 24, 2008, Nebraska Public Power District submitted an application pursuant to 10 CFR Part 54, to renew the operating license, DPR-46, for Cooper Nuclear Station for review by the U.S. Nuclear Regulatory Commission (NRC or the staff). The staff is reviewing the information contained in the license renewal application and the associated Environmental Report submitted. The staff has identified, in the enclosure, areas where additional information is needed to complete the review. Further requests for additional information may be issued in the future.

Items in the enclosure were discussed with Mr. David Bremer. A mutually agreeable date for the response is within 30 days from the date of this letter, in order to maintain the license renewal review schedule. If you have any questions, please contact Emmanuel Sayoc at 301-415-1924 or by e-mail at emmanuel.sayoc@nrc.gov, or Tam Tran at 301-415-3617 or by e-mail at tam.tran@nrc.gov.

Sincerely,

/RA/

Tam Tran, Project Manager
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket No. 50-298

Enclosure:
As stated

cc w/encl: See next page

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Tam Tran, Project Manager
Projects Branch 1
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OFFICE	PM:DLR:RPB2	LA:DLR	PM:DLR:RPB2	BC:DLR:RPB1
NAME	ESayoc (TTran for)	Iking	TTran	DPelton
DATE	06/05/09	06/05/09	06/05/09	06/08/09

OFFICIAL RECORD COPY

Letter to Stewart. B. Minahan from Tam Tran, dated June 08, 2009

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE COOPER NUCLEAR STATION LICENSE RENEWAL APPLICATION (TAC NO. MD9763 AND MD9737)

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COOPER NUCLEAR STATION LICENSE RENEWAL
REQUEST FOR ADDITIONAL INFORMATION

A. Environmental RAI

ENV-SAMA-1

1. Provide the following information regarding the probabilistic safety analysis (PSA) used for the severe accident mitigation alternatives (SAMA) analysis:

    a. There are three core damage frequency (CDF)-related estimates reported in Attachment E to the environmental report (ER); i.e., 9.27E-06 per year in Table E.1-1 (CDF by Major Initiators), 9.23E-06 per year in Table E.1-8 (CDF by Plant Damage State), and 1.16E-05 per year in Table E.1-9 (Release Frequency by Release Category). Explain the reasons for the differences in these values, and the rationale for selecting the total release frequency as the baseline frequency for evaluating SAMA benefits.

    b. Section E.1.4.6 describes the May 2008 Boiler Water Reactor Owners Group (BWROG) peer review of the 2007TM model, Revision 1. Cooper Nuclear Station's (CNS's) review of the preliminary peer review findings determined that resolution of the findings would not result in a significant impact on the probabilistic risk analysis (PRA) results, and that the areas considered "not met" or capability category I have a negligible effect on the baseline CDF. For each peer review finding, provide a summary of the finding and an assessment of the impact of resolution of the finding on the SAMA identification and analysis results. The response should also address each of the supporting requirements having a capability category considered "not met" or capability category I, and discuss its potential impact on the SAMA identification and analysis results.

ENV-SAMA-2

2. Provide the following information relative to the Level 2 analysis:

    a. Table E.1-10 identifies the release fractions for each release mode. The release fractions for iodine and cesium for the LL/I release mode are significantly lower than the corresponding release fractions for both the LL/E and LL/L release modes. Provide an explanation for this apparent anomaly.

    b. In the discussion of the Level 2 analysis (Section E.1.2), the process used to develop and group the source terms into containment event tree (CET) end states is not clear.

        i. Clarify whether a single CET was used for the grouping of source terms, or whether a single CET was used for each accident class or for each plant damage state (PDS). Provide a typical CET showing release categories assigned to each end state.

ii. For each CET sequence, mass fractions obtained from the representative MAAP calculations were “weighed according to the contribution of that sequence to the sum of the sequences in the end state bin” (page E.1-68). Identify and describe the number of MAAP calculations or runs made to obtain the mass fractions. Provide an example of the weighting calculation for a representative CET sequence.

c. Table E.1-5 shows three events (CNT-SMP-FF-MLTOF, RPV-DWV-FO-BARIS, and CNT-MDL-FF-WTRCV) having a risk reduction worth (RRW) value of 2.181. Provide details on which portions of the large early release frequency (LERF) model are affected in the computation of the RRW.

ENV-SAMA-3

3. For each of the dominant fire areas, explain what measures, if any, have already been taken (since the individual plant examination of external events (IPEEE)) to reduce fire risk. Include in the response specific improvements to fire detection systems, enhancements to fire suppression capabilities, changes that would improve cable separation and drain separation, and improvements to processes/procedures for monitoring and controlling the quantity of combustible materials in critical areas.

ENV-SAMA-4

4. Provide the following information concerning the MACCS2 analyses:

   a. Specify the fraction of the public that was assumed to participate in an evacuation at CNS. NUREG-1150 assumed a 99.5 percent evacuation within the emergency planning zone (EPZ); previous SAMA analyses have assumed a 95 percent evacuation. If a 95 percent evacuation was not assumed at CNS, address the potential impact on the off-site exposure risk and averted public exposure cost if 5 percent of the population fails to evacuate the EPZ.

   b. In Section E.1.5.2.8, it is stated that the core inventory is based on a bounding reload core immediately following shutdown. Provide the core enrichment and burnup used in the MAACS2 analyses. Confirm that this core inventory reflects the expected fuel management/burnup during the renewal period.

ENV-SAMA-5

5. Provide the following with regard to the SAMA identification and screening process:

   a. Table E.1-5 identifies the RRW for events that contribute to LERF. The table appears to contain success events and associated SAMAs. For example, CGS-PHE-FF-INERT represents successful containment inerting and has the highest RRW value in the table (3.417). Another example is RPV-MDL-SC-C1A1E, successful depressurization (Class IA, IE), which has an RRW value of 1.335. Discuss the rationale for identifying SAMAs for success events.

   b. There appear to be events in Table E.1-5 that are complementary (e.g., as the probability of event A approaches zero, the probability of event B approaches 1.0. Evaluation of RRW for these events would need to consider this relationship. To examine how this relationship between events was addressed in Table E.1-5, provide the value used for CGS-PHE-SC-INERT (containment not inerted; venting required) when calculating the RRW for CGS-PHE-FF-INERT (containment inerted; venting not required). If the value of this and other complementary events were not directly coupled in the computation of the RRWs, provide a revised Table E.1-5 with these events appropriately addressed [i.e., the probability of event CGS-PHE-SC-INERT is set equal to 1.0 when the probability of event CGS-PHE-FF-INERT is set equal to 0.0). Provide an assessment of the results on the SAMA identification and evaluation.

c. From Table E.1-3, event TDCA (loss of 125 VDC A) and event EDC-XHE-FO-RSTA (failure to restore DC power within 30 minutes) have RRW values of 1.19, which would imply a potential CDF reduction for DC power improvements of about 20 percent. These events are addressed by SAMAs 1, 2, 3, 13, 14, 15, 19, and 21, which in turn are covered by analysis cases 1 through 5 and 14. However, these analysis cases show a CDF reduction (in Table E.2-2) of about 3 percent or less (except for analysis case 14). Explain why there are not additional DC power-related SAMAs for these basic events that have potentially greater CDF reduction impacts than 3 percent. For example, provide the rationale for why a procedural SAMA addressing event EDC-XHE-FO-RSTA with a potential CDF reduction of about 20 percent was not considered.

d. Event PCI-CNT-FF-PREEX (pre-existing containment failure) has an RRW of 1.056. All of the SAMAs considered for this event involve major hardware modifications. Provide an assessment of the costs and benefits of lower cost SAMAs for this event (e.g., periodic monitoring of containment integrity during normal operation or procedures to isolate the containment following an event).

e. ER Section E.2.2, identified three criteria used to screen Phase I SAMAs, all of which are qualitative. However, information provided in the "Screening Results" column of Table E.2-1 suggests that other criteria were used, including "Small CDF Reduction" (SAMAs 209, 227, and 229), and "Outliers Were Resolved Analytically" (SAMAs 217, 220, 221, 224, 226, and 227). Clarify the criteria used to perform the Phase I screening.

f. Table E.2-2, describes SAMA 21 as being part of SAMA 13 and no separate evaluation is provided. Explain the rationale for including SAMA 21 as a unique SAMA if it cannot be implemented as an independent SAMA.

g. In Table E.2-1, SAMA 232 (protect the diesel exhaust from tornado generated missiles) is described as being resolved by a modification completed in 1998. However, in the NRC safety evaluation report (SER) on the CNS IPEEE dated April 2001, the issue is described as yet to be addressed in the IPEEE Issue Resolution Plan. Clarify this apparent discrepancy.

ENV-SAMA-6

6. Provide the following with regard to the Phase II cost-benefit evaluations:

    a. For a number of the Phase II SAMAs listed in Table E.2-2, the information provided does not sufficiently describe the associated modifications and what is included in the cost estimate. Provide a more detailed description of both the modifications and the cost estimates for Phase II SAMAs 20, 44, 45, 63, 70, 72, 73, 76, 77, and 80. Also, for SAMA 76 describe what is meant by “group 1 isolations” in the context of both the plant and the PRA model.

b. Analysis case 14 covers SAMA 14 (portable generator for DC power to supply individual panels), SAMA 22 (install independent high-pressure injection (HPI) system), and SAMA 23 (additional HPI pump with independent diesel). For this case, high-pressure coolant injection (HPCI) unavailability was set to zero resulting in a 32 percent reduction in CDF. However, event HCI-SYS-TM-HPCI (HPCI unavailable due to test and maintenance) has an RRW equal to 1.03.

    i. Explain the rationale for assigning SAMA 14 to analysis case 14, and for estimating the benefit for this SAMA by setting HPCI unavailability to zero.

    ii. Explain the large CDF reduction (32 percent) when the RRW for HPCI unavailability due to test and maintenance would suggest only a 3 percent reduction. Clarify whether loss of DC panel power is the dominant contributor to HPCI unavailability. Identify the other significant contributors to HPCI unavailability.

c. In Table E.2-2, the modeling assumption for SAMA 6 (i.e., change the time available to recover offsite power to 24 hours) is inconsistent with the modeling assumption of analysis case 6 (i.e., set failure to transfer the reactor protection system panels to their alternate power source to zero). Clarify which description is correct. Provide a revised evaluation, if necessary.

d. Table E.2-2 describes the bounding analysis for SAMA 78 as “reducing operator actions that could be improved via training for alternate injection via the fire water system by a factor of 2.” The description provided for the corresponding analysis case 23 (page E.2-8) is similar. Provide a clarification of how the evaluation of this SAMA was modeled in the PRA. Identify the associated operator action(s) and the initial and modified human error probability value(s).

e. SAMA 41 (modify procedure to provide ability to align diesel power to more air compressors) has an estimated cost of $1.2M. This cost appears high for what appears to be a procedure and training issue. Justify the cost estimate for this SAMA.

f. SAMA 69 (upgrade the seismic capacity of the diesel fire pump fuel tank and water supply tank) is intended to increase the reliability of the fire water system in seismic events. The benefit of this SAMA was determined by eliminating failure of the diesel-driven fire pump. Discuss how eliminating failure of the diesel-driven fire pump in the internal event model, in conjunction with the external event multiplier, captures the benefit from this SAMA in seismic events. Justify the benefit and cost estimates for this SAMA.

g. SAMA 14 (portable generator for DC power to supply the individual panels) and SAMA 13 (portable generator for DC power to supply the battery chargers) both involve use of a portable generator. SAMA 14 is cost beneficial while SAMA 13 is not. Discuss whether it is feasible for SAMA 13 to use the same portable generator as SAMA 14, and if so, provide a revised evaluation of SAMA 13.

h. SAMA 70 (install a curb to prevent debris from spreading across the floor and contacting the shell) has a CDF reduction of 11.6 percent. Explain how this SAMA reduces CDF, and identify the events in Table E.1-3 that are impacted.

i. SAMA 75 (implement generation risk assessment into plant activities) has a large benefit owing to the many risk contributors that it impacts. Provide a detailed description of this SAMA, including: (1) a discussion of how it would be implemented at CNS, (2) a more comprehensive description of analysis assumptions, (3) justification for the assumed factor of 2 reduction in initiating event frequency for affected events, and (4) a more detailed discussion of the estimated implementation cost.

j. Pages 4-83 and E.2-2 of the ER indicate that the SAMA cost estimates did not include the cost of replacement power during extended outages required to implement the modifications, nor did they account for inflation. Clarify how other cost factors were treated in these estimates, specifically, contingency costs associated with unforeseen implementation obstacles, and maintenance and surveillance costs.

k. Explain why a factor of 3 is used to represent uncertainty, given that the ratio of the 95th percentile CDF to the mean CDF is said to be 1.86. Provide the 5th percentile, mean, and 95th percentile CDF values.

l. The CNS cost-benefit analysis showed that eleven of the SAMA candidates (SAMAs 14, 25, 30, 33, 40, 45, 64, 68, 75, 78, and 79) were potentially cost-beneficial.

   i. The ER does not provide any indication of CNS's plans regarding the eleven Phase II SAMAs found to be potentially cost-beneficial. Describe CNS's plans regarding these SAMAs, and any other potentially cost-beneficial SAMAs that may emerge from further analyses in response to these RAIs.

   ii. In view of the significant number of potentially cost-beneficial SAMAs, it is likely that several of these SAMAs address the same risk contributors. As such, implementation of an optimal subset of these SAMAs could achieve a large portion of the total risk reduction at a fraction of the cost, and render the remaining SAMAs no longer cost-beneficial. In this regard: (1) identify those SAMAs that Nebraska Public Power District (NPPD) considers highest priority for implementation, (2) provide an assessment of the impact on the remaining SAMAs if these high-priority SAMAs are implemented, and (3) identify those SAMAs that would no longer be cost-beneficial given implementation of the high-priority SAMAs. Also, provide any specific plans/commitments regarding implementation of the high priority SAMAs.

ENV-SAMA-7

7. For certain SAMAs considered in the ER, there may be lower-cost alternatives that could achieve much of the risk reduction at a lower cost. In this regard, discuss whether any lower-cost alternatives to those Phase II SAMAs considered in the ER, would be viable and potentially cost-beneficial. Evaluate the following SAMAs (previously found to be potentially cost-beneficial at other plants), or indicate if the particular SAMA has already

been considered. If the latter, indicate whether the SAMA has been implemented or has been determined to not be cost-beneficial at CNS:

a. Provide additional space cooling to the residual heat removal service water (RHRSW) booster pump rooms, CS pump rooms, residual heat removal pump rooms, service water pump rooms, and HPCI pump room via the use of portable equipment (in lieu of a redundant train of RHRSW booster pump room ventilation considered in SAMA 35).

b. Improve alternate shutdown training and equipment (in lieu of upgrading the ASDS panel considered in SAMA 65). The intent of this alternative is to reduce the human error probability of required actions by improving training on operating the plant from outside the control room and improving communications equipment and plans for coordination among local operators (see Brunswick Phase II SAMA 31).

c. Enhance dc power availability (provide cables from diesel generators or another source to directly power battery chargers).

d. Develop guidance/procedures for local, manual control of reactor core isolation cooling following loss of dc power.

e. Manual venting of containment using either a local hand wheel or gas bottle supplies (considered for Nine Mile Point Unit 1) as a possible alternative for containment pressure control.

B. Safety RAI

RAI 3.3.2.2.3.3-1

Background:
Section 3.3.2.2.3.3 "Cracking due to Stress Corrosion Cracking (SCC)" of the Standard Review Plan-License Renewal (SRP-LR) identifies SCC as an aging effect requiring management for stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust. The generic aging lessons learned (GALL) report identifies this MEAP combination in Item VII.H2-1. Aging management review (AMR) Item AP-33 in Table II.A of NUREG-1833, "Technical Bases for Revision to the License Renewal Guidance Documents," provides a basis for why it is important to identify SCC as an aging effect requiring management (AERM) for the internal surfaces of stainless steel emergency diesel generator exhaust piping that are exposed to diesel exhaust. Specifically, NUREG-1833 states that hot diesel engine exhaust may contain moisture and particulates which lead to SCC in stainless steel diesel exhaust components.

Issue:
Contrary to the License Renewal Guidance identified above, the applicant states that stainless steel exhaust components are not subject to significant moisture accumulation that would allow cracking to occur. The staff disagrees with this approach, and takes the position that this must be identified as an AERM similar to the GALL Item VII.H2-1.

Request:
Please provide an aging management program (AMP) and AMR line item to manage the aging effect recommended by GALL VII.H2-1

RAI 3.3.2.2.7.3-1

Background:
Section 3.3.2.2.7.3, "Loss of Material due to General, Pitting, and Crevice Corrosion" of the SRP-LR identifies loss of material as an AERM for steel and stainless steel diesel exhaust piping, piping components, and piping elements exposed to diesel exhaust. The applicant has credited the plant specific AMP B.1.31, Periodic Surveillance and Preventive Maintenance (PSPM) Program with managing this aging effect for emergency diesel generator exhaust piping, piping components, and piping elements.

Issue:
The PSPM Program identifies the use of visual inspections performed on a "representative sample" of diesel generator exhaust gas components to manage the loss of material aging effect. The AMP indicates that sample size is determined using guidance from EPRI TR-107514, Age-Related Degradation Inspection Method and Demonstration, for a 90% confidence level that 90% of the population does not experience degradation. However, it is not clear what the population and sample size will be for the diesel generator system exhaust components. Additionally, the AMP indicates that "components with the same material-environment combinations at other facilities may be included in the sample." The inspection of components at other facilities would not necessarily offer an accurate representation of the aging effects at the current facility, and thus brings into question the extent of which this method will be used and the effect of its inclusion on the overall population and sample size.

Request:

a) Please provide the total actual population and sample size of diesel generator exhaust gas components to manage the loss of material aging effect at CNS.
b) Please clarify the use of “inspection of components at other facilities” as part of the representative sample for diesel generator exhaust gas components to manage the loss of material aging effect at CNS, and identify the specific impact this will have on the overall population and sample size.

RAI 3.3.2.2.7.3-2

Background:

Section 3.3.2.2.7.3, “Loss of Material due to General, Pitting, and Crevice Corrosion” of the SRP-LR identifies loss of material as an AERM for steel and stainless steel diesel exhaust piping, piping components, and piping elements exposed to diesel exhaust. The applicant has credited the plant specific AMP B.1.16, Fire Protection Program with managing this aging effect for the diesel fire pump engine exhaust piping, piping components, and piping elements.

Issue:

License renewal application (LRA) AMP B.1.16, Fire Protection Program states as an enhancement that the diesel fire pump engine carbon steel exhaust components are inspected for evidence of corrosion or cracking. However, the LRA is not clear whether the inspection will be an internal inspection or external only. An internal inspection is necessary to inspect for the aging effects caused by exhaust gas.

Request:

Please clarify whether the inspection conducted by the Fire Protection Program includes the internal surface of the components.

C. Revised RAI

RAI B.1.15-9

Based on the conference call between the staff and the applicant on May 20, 2009, this RAI was updated as follow:

Background:
Program Element 4 of NUREG-1801 Section X.M1 is concerning detection of aging effects. Under the CNS Fatigue Monitoring Program, B.1.15 (CNS-RPT-LRD02, Revision 1), program Element 4 Subsection B states: “No actions are taken as part of this program to detect aging effects … If a design cycle assumption is approached, corrective action is taken which will include update of fatigue usage calculation, if necessary.”

In addition, Program Element 5 of NUREG-1801 Section X.M1 is concerning monitoring and trending. Under the CNS Fatigue Monitoring Program, B.1.15 (CNS-RPT-LRD02, Revision 1), Program Element 5, Subsection B, it states: “The Fatigue Monitoring Program monitors the number of pressure and temperature transient cycles and periodically compares this cycle count with the design cycle count to ensure that fatigue sensitive components remain within their allowable design…”

Issue
Clarification is deemed necessary, as described below. Additionally, Element 5 indicates that only the feedwater nozzle will be monitored.

Request
(a) Please provide basis why taking “no action” will achieve the goal of detecting aging effects.

(b) Please explain why “design cycle” can be used as basis for detecting aging effects when the design transients do not include all thermal events actually experienced by the reactor coolant pressure boundary components, as discussed in RAI B.1.15-2.

(c) The LRA states that the environmental fatigue analyses were performed based on the 60-year projected cycles and LRA Table 4.3-1 shows that the 60-year projected cycles for most of the transients are less than the design cycles. With these conditions in mind, components could have failed before the design cycles are approached. Provide justification that the design cycles can be used as criteria to detect aging effects.

(d) GALL requires all high fatigue locations are monitored, not just at the most limiting location within the applicable NUREG/CR-6260 locations, as minimum. Please provide justification that CNS will monitor the feedwater nozzle only.

RAI B.1.15-10

Based on the conference call between the staff and the applicant on May 20, 2009, this RAI was updated as follow:

Background:
Program Element 6 of NUREG-1801 Section X.M1 is concerning acceptance criteria. Under the CNS Fatigue Monitoring Program, B.1.15 (CNS-RPT-LRD02, Revision 1), Program Element 6 Subsection B states: "The Fatigue Monitoring Program acceptance criteria are that none of the transients exceeded the allowable numbers in USAR Table III-3-1 …"

Issue:
Clarification is deemed necessary, as described below.

Request:

(a) Questions (b) and (c) of RAI B.1.15-3 apply here. Please explain accordingly.

(b) GALL Section X.M1 Element 6 requires maintaining fatigue usage below the design code limit considering environmental fatigue effects. CNS Fatigue Monitoring Program Element 6 does not mention environmental fatigue effects. Please explain why.