August 10, 2009

Mr. Jon Franke, Vice President
Crystal River Nuclear Plant (NA1B)
ATTN: Supervisor, Licensing & Regulatory
Programs
15760 West Power Line Street
Crystal River, FL 34428-6708

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION REGARDING SEVERE ACCIDENT MITIGATION ALTERNATIVES FOR CRYSTAL RIVER UNIT 3 NUCLEAR GENERATING PLANT LICENSE RENEWAL APPLICATION (TAC NO. ME0278)

Dear Mr. Franke:

The U.S. Nuclear Regulatory Commission staff has reviewed the Severe Accident Mitigation Alternatives analysis submitted by Progress Energy for the Crystal River Unit 3 Nuclear Generating Plant (CR-3) license renewal and has identified areas where additional information is needed to complete its review. Enclosed is the staff's request for additional information.

We request that you provide your responses to these questions within 60 days of the date of this letter, in order to maintain the license renewal review schedule. If you have any questions, please contact Elaine Keegan by telephone at 301-415-8517 or by e-mail at Elaine.Keegan@nrc.gov, for the review of the CR-3 license renewal application.

Sincerely,

/RA/

Elaine M. Keegan, Sr. Project Manager
Projects Branch 2
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket No. 50-302

Enclosure:
As stated

cc w/encl: See next page

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Sincerely,

/RA/

Elaine M. Keegan, Sr. Project Manager
Projects Branch 2
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OFFICE	PM:RPB2:DLR	LA:RPOB:DLR	BC:APLA:DRA	BC:RPB2:DLR	PM:RPB2:DLR
NAME	EKeegan	IKing	DHarrison	DWrona	EKeegan (Signature)
DATE	08 /04/09	07/16/09	08/04/09	08/06/09	08/10/09

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Letter to Jon Franke from David J. Wrona dated August 10, 2009

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION REGARDING SEVERE ACCIDENT MITIGATION ALTERNATIVES FOR CRYSTAL RIVER UNIT 3 NUCLEAR GENERATING PLANT LICENSE RENEWAL APPLICATION (TAC NO. ME0278)

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E Keegan
RKuntz
DBrittner
DLogan
AJones, OGC
LLake, RII
MSykes, RII
TMorrissey, RII

Request for Additional Information
Regarding the Analysis of Severe Accident Mitigation Alternatives
for Crystal River Nuclear Power Plant Unit 3 (CRNPP)

1. Provide the following information regarding the Level 1 Probabilistic Safety Assessment (PSA) used for the Severe Accident Mitigation Alternatives (SAMA) analysis:

   a. Section E.2.1 provides a detailed description of the PSA model changes made since the IPE Level 1 model.

      i. Provide the core damage frequency (CDF) and large early release frequency (LERF) for each version of the PSA Model of Record (MOR) to demonstrate how changes in the PSA model impacted the calculated CDF and LERF.

      ii. For each version of the PSA, identify the model changes listed in Section E.2.1 that most impacted the change in CDF and LERF.

   b. Section E.2.2.1 states that the MOR 2006 PSA model used for the SAMA analysis reflects Crystal River Nuclear Power Plant (CRNPP) as designed and operated up to April 2006. Identify any changes to the plant (physical and procedural modifications) since April 2006, that could have a significant impact on the results of the PSA and/or the SAMA analyses. Provide a qualitative assessment of their impact on the PSA and on the results of the SAMA evaluation.

   c. Section E.2 states that an industry peer review was performed on the MOR 2000 PSA model and that all Level A, B, C, and D Facts and Observations (F&Os) have been addressed and closed. Section E.2.1.1.10 further states that the Level 2 PSA was not completed in time to support the industry Peer Review. In light of this, and the fact that the peer review of the PSA was performed several years prior to the development of the MOR 2006 PSA model used for the SAMA analysis, provide a description of the quality controls applied to the development of the MOR 2006, Level 1 and 2 PSA model. Identify and discuss any additional internal and external reviews. Describe any significant review comments, their resolution, and the potential impact of any unresolved comments on the results of the SAMA analysis.

   d. Figure E.2-1 provides the contribution to CDF by initiator as a percentage of the internal events CDF (4.99E-06/yr). Provide the actual numerical value for the CDF contribution for each initiator that sums to the total internal events CDF.

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

   a. Describe how the Level 2 model used for the SAMA analysis differs from the Individual Plant Examination (IPE) backend analysis.

   b. Table E.5-2, Level 2 Importance List Review for Risk Reduction Worth (RRW) Greater than 1.02, presents the basic events with an RRW greater than 1.02 for LERF sequences. Not counting flags, split fractions and initiating events only five basic events

are presented. Explain why there are so few basic events with an RRW greater than 1.02 for LERF sequences. Specifically address why there are no loss of offsite power-related events. Also, provide the Risk Reduction Worth values for each entry in Table E.5-2.

c. Section E.2.1.3.10, states that certain sequences (i.e. MK, SK, RK ATWS) were deleted from the Level II PSA model due to low frequency. Provide the cutoff frequency used to delete these sequences. Also, define MK, SK, and RK ATWS.

d. Provide a breakdown of the CDF and population dose by containment release mode (e.g., intact containment, containment isolation failure, containment bypass – Steam Generator Tube Rupture [SGTR], containment bypass – ISLOCA, IVR).

e. In the discussion of the Level 2 analysis (Sections E.2.2.2, E.2.2.3 and E.3.4), the process used to map Level 1 results into the Level 2 model and group the containment event tree (CET) end states into release categories is not clear.

   i. Provide a description of the process used to map the Level 1 results into the Level 2 analysis. Describe the plant damage states and how they were applied.

   ii. Provide a description of the process used to group the containment event tree (CET) end states into release categories. Provide a typical CET showing release categories assigned to each end state.

   iii. Identify and describe the number of Modular Accident Analysis Program (MAAP) calculations made to obtain the fission product release fractions for each release category. Provide an example of the weighting calculation for a representative CET sequence. Also, identify the version of MAAP used in the SAMA evaluation.

   iv. Section E.5.1.2 explains that "…even though Release Categories 3B and 4C were not contributors to LERF, they were large contributors to Level 3 offsite consequence" and that a review was performed to determine if further risk dominant basic events could be identified. Section E.5.1.2 goes on to explain that no new dominant risk contributors not already identified from Level 1 results were found. Whereas Table E.5-2 identifies the LERF sequences having RRW values greater than 1.02, no corresponding table or information is presented that shows how risk importance events contributing to Release Categories 3B or 4C were reviewed. Identify the risk contributors from the Level 1 review that are also dominant contributors to Release Categories 3B and 4C and clarify why these are the dominant risk contributors.

3. Provide the following information with regard to the treatment and inclusion of external events in the SAMA analysis:

   a. Provide fire CDF by fire zone/area and the total fire CDF for CRNPP. If the fire CDF is different than that reported in the Individual Plant Examination for External Events (IPEEE), provide an explanation for the differences.

b. For each of the dominant fire areas, explain what measures, if any, have already been taken (since the 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 improvements to processes/procedures for monitoring and controlling the quantity of combustible materials in critical areas.

c. The SAMA analysis assumes that risks posed by external and internal events is approximately equal (page E.5-7). Based on this assumption, the estimated benefit from reduction of internal event risk was doubled to account for a corresponding reduction in external event risk. However, Section 1.4 of the IPEEE identifies the calculated CDF from fires to be 4.2E-05 per year, a factor of 8.5 greater than the internal events CDF (4.95E-06 per year) used in the SAMA analysis. Furthermore, while a seismic CDF was not developed for the IPEEE, the U.S. Nuclear Regulatory Commission (NRC) staff estimates the seismic CDF for CRNPP to be about 1.2E-05 per year using the approximation method described in a paper by Robert P. Kennedy, "Overview of Methods for Seismic PRA and Margin Analysis Including Recent Innovations" and using updated 2008 seismic hazard curve data from the U.S. Geologic Survey (USGS). Based on this, provide justification for why a multiplier of 12 [(4.2E-05 + 1.2E-05) / 4.95E-06 + 1] shouldn't be used to account for the additional risk of all external events (seismic, fire, high winds, etc.) rather than the multiplier of two used in the SAMA analysis.

d. Provide an assessment of the impact on the initial and final SAMA screenings if the internal events risk reduction estimate is increased by a factor of 12 (or a smaller factor for which sufficient basis can be provided). Provide a Phase II analysis for any Phase I SAMAs that were screened out in the Environmental Report (ER) but would not have been with the higher factor.

e. Section E.5.1.6 of the ER notes that at the time of the 1997 IPEEE submittal, the plan was for CRNPP's plant-specific response to unresolved safety issue (USI) A-46, "Seismic Qualification of Equipment in Operating Plants," to sufficiently address seismic risk. The USI A-46 safety evaluation report (SER) in 2000 identified three topics that required additional work to resolve: 1) one equipment seismic capacity outlier, 2) five outliers associated with differences between the caveats in generic implementation procedure (GIP)-2 and those in the plant-specific procedure (PSP), and 3) revision of abnormal procedure (AP)-961. The USI A-46 SER further states that each of these issues is being tracked in the CR-3 Corrective Action Program. ER Section E.5.1.6 is silent as to the status of these issues. Clarify the resolution status of each of these unresolved issues. If still unresolved, identify and evaluate seismic SAMAs to address each unresolved issue.

4. Provide the following information concerning the MACCS2 analyses:

a. Section 2.12.1 of the Environmental Report states that "*Progress Energy plans to increase CR-3's licensed power level and electrical output by approximately 20 percent in an Extended Power Uprate (EPU) scheduled to be carried out during fall 2009 and fall 2011 refueling outages*." Operation at this higher power level could impact the results of

the SAMA evaluation due to the higher fission product inventory and replacement power costs associated with the EPU. Provide a revised SAMA analysis (baseline and uncertainty) assuming operation at the uprated power level.

b. Section E.3.2 states that county growth rates were applied to the year 2000 population to develop the SECPOP2000 population sector distribution.

   i. Section E.3.2 does not discuss transient population. Clarify whether transient population was considered in the analysis. If a transient population was not considered, either provide a justification/rationale for not including this or estimate the potential impact on the population dose risk and the SAMA evaluation.

   ii. Provide the year 1990 Emergency Planning Zone (EPZ) population used for the evacuation study.

c. The MACCS2 analysis yielded a total population dose risk (PDR) and off-site economic cost risk (OECR) of 3.98 person-rem/year and 6,950 $/year, respectively, as reported in Table E.3-7. However, per Section E.4.6, the Phase I and II SAMA evaluations utilized a PDR and OECR of 3.79 person-rem/year and 6,624 $/year, respectively. Clarify the discrepancy and, if necessary, provide a revised SAMA evaluation.

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

a. Section E.5.1.7 identifies the 4.16 kV Switchgear Bus Room 3A, along with Battery Charger Room 3A, as being significant contributors to the fire CDF based on the IPEEE (i.e., 17% and 36%, respectively). IPEEE Section 1.4 also identifies 4.16 kV Switchgear Bus Room 3B as having a CDF similar to Room 3A. The uncertainty analysis for SAMA 49, Upgrade Fire Barriers in Battery Charger Room 3A, shows this SAMA to be cost beneficial. Provide justification for why a SAMA(s) for the 4.16 kV Switchgear Bus Rooms 3A and 3B should not be considered and evaluated.

b. Table E.5-1, Level 1 Importance List Review, identifies SAMA 5 as a mitigation strategy for event QHUFWP7Y, however Section E.6.8 does not identify that event as being mitigated by SAMA 5. Clarify this discrepancy.

c. Table E.5-1, Level 1 Importance List Review, identifies event HHUMPSBY, OPERATORS FAIL TO START STANDBY MAKEUP PUMP, as having an RRW value of 1.059 and a failure probability of 1.0E+00. It is further stated that a SAMA was not formulated because the current procedures and training are believed to be adequate to start and align the standby makeup pumps. Explain why the failure probability for this event is 1.0E+00 if the procedures and training related to this event are adequate. Provide further justification for why a SAMA that improves procedures and training, or provides for a hardware modification, is not applicable.

d. Table E.5-1, Level 1 Importance List Review, identifies event APWNR01R, BOTH EDGS FTS, BOTH EFPS FTS, as having an RRW value of 1.044 and a probability of 6.40E-01. This failure denotes the likelihood that AC power will not be recovered in time for

specified failures. It was further stated that "*No specific SAMA was identified to change the AC power non-recovery value but a SAMA was identified to provide an additional EDG*". The SAMA identified was SAMA 18 at an estimated cost of more than $5,000,000.

i. Provide further justification for why a SAMA to enhance procedures and training is not considered.

ii. Provide an evaluation of the costs and benefits of providing AC power from one of the other Crystal River power plants (Crystal River 1 and 2).

e. Table E.5-1, Level 1 Importance List Review, identifies event HHUMBACY, OPERATOR FAILS TO SWITCH MUP-1B POWER SOURCE, as having an RRW value of 1.027 and a probability of 1.0E+00. This event is described as failure to locally swap power supply to the "swing" pump. Proposed SAMA 15 is described as providing remote control room capability to realign power to pump MUP-1B. The cost of this SAMA was estimated to be $400,000 and was determined not to be cost beneficial. Provide an evaluation of the costs and benefits of developing local manual swap-over procedures and training (or enhancing procedures and training if they exist) in lieu of SAMA 15.

f. Table E.5-1 identifies several initiating events for which no SAMA was identified to reduce probability, but for which "basic events relating to mitigation are addressed separately." Identify the basic events and associated SAMAs that mitigate these initiating events, including: IE_S (small break LOCA), IE_R (steam generator tube rupture), IE_T11 (loss of intake), IE_T3 (loss of offsite power), IE_T1 (reactor trip), IE_T8 (loss of 4160V ES Bus 3A), IE_A (large break LOCA), IE_T16 (loss of makeup), IE_T2 (loss of main feedwater), and IE_T10 (loss of NSCCC).

g. Section E.5.1 states that industry Phase II SAMAs were reviewed for potential applicability to CRNPP, but does not identify the specific nuclear plants reviewed. Section E.11 references the SAMA analyses for Calvert Cliffs, Robinson, and Brunswick nuclear power plants. Clarify if these were the plants for which the industry Phase II SAMA review was performed, and if there were other plants included in the review. Also clarify whether any of the Phase I SAMAs were identified as a result of the CRNPP review of these other SAMA analyses.

h. Section 4.20 states that approximately 25 Phase I SAMAs were identified for consideration in the SAMA analysis. Table E.5-3 lists and describes each of these Phase I SAMAs. The SAMA numbers for these SAMAs range from 1 to 52, are not consecutive, and do not correspond to the SAMA ID Numbers for the industry SAMAs identified in Addendum 1. This suggests that a pre-screening of the identified SAMAs occurred prior to the Phase I screening. Clarify the process used to develop the Phase I SAMAs. Furthermore, on p. E.7-3 it is stated that the Phase I screening process involved qualitative disposition of 9 SAMAs. Based on review of Table E.5-3 and the discussion in Section E.5.2, it appears that: (1) the Phase I screening was quantitative rather the qualitative, and (2) 10 SAMAs were screened out versus 9. Clarify the Phase I screening process.

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

   a. Section E.6 introduction states that CRNPP specific implementation cost estimates were developed by plant personnel, and footnote 1 to Table E.5-3 states that "*Cost estimates provided/validated by CRNPP*." Section E.5.1.1 further states that procedural changes have previously been estimated to cost about $50,000. Beyond this, no further basis is provided for implementation cost estimates. Provide a general explanation of the basis for CRNPP-specific SAMA implementation cost estimates developed by plant personnel.

   b. For a number of the Phase II SAMAs listed in Table E.6-1, 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 4, 5, 15, 35, and 49.

   c. Analysis of SAMA 49, Upgrade Fire Barriers in Battery Charger Room 3A (Section E.6.15), assumes a 13.1 percent risk reduction. This is based on two assumptions: 1) the contribution of Battery Charger Room 3A to the total (external + internal) CDF is 26.3 percent and 2) the external event CDF approximately equals the internal events CDF. However, IPEEE Section 1.4 indicates that the CDF for this room (1.49E-05 per year) is 149 percent of the internal event (including internal flooding) risk (about 1.0E-05 per year). Justify the benefit estimate for this SAMA (see related RAIs 3.a - 3.d).

   d. Table E.5-1, Level 1 Importance List Review, identifies potential SAMAs 5 and 7 to address event QHUFWP7Y, OPERATORS FAIL TO START FWP-7. But Table E.5-2, Level 2 Importance List Review for RRW Greater than 1.02, identifies potential SAMA 4 to address this same event, QHUFWP7Y. Neither SAMA 4 nor SAMA 5's benefit evaluation considers the risk reduction related to event QHUFWP7Y. Since SAMA 5 improves maintenance unavailability, it appears that SAMA 4, Automatic Start of Auxiliary Feedwater Pump (FWP-7) When Required, is the appropriate SAMA to address QHUFWP7Y. Clarify which SAMA(s) were considered to address event QHUFWP7Y, and explain why the risk reduction associated with mitigation of event QHUFWP7Y is not credited in the analysis of SAMA 4.

   e. SAMA 16 (enhance procedures and make design changes as required to facilitate crosstying trains of DH, DHCC, etc.) has an estimated cost of $5M. This cost appears high for what appears to be mostly a procedure issue. Justify the cost estimate for this SAMA.

   f. Section E.7.2.1 states that no additional Phase I SAMAs were retained for further analysis as a result of the uncertainty analysis using the 95th percentile CDF. Using the 95th percentile CDF results in a Modified Maximum Averted Cost-Risk (MMACR) of $1.4 million ($682,000 x 2.1). This is more than a factor of 2 greater than the cost estimates for Phase I SAMAs 8, 14, 26, 37, and 52. Provide a Phase II evaluation of these SAMAs.

7. Section 4.20 states that “Progress Energy will consider the four SAMAs using the appropriate CR-3 design process.” Describe the “CR-3 design process” and clarify how the four SAMAs, and any other SAMAs determined to be potentially cost-beneficial in response to these RAIs, are evaluated using this process.

Crystal River Unit 3 Nuclear Generating Plant

cc:

Mr. R. Alexander Glenn
Associate General Counsel (MAC-BT15A)
Florida Power Corporation
P.O. Box 14042
St. Petersburg, FL 33733-4042

Mr. James W. Holt
Plant General Manager
Crystal River Nuclear Plant (NA2C)
15760 W. Power Line Street
Crystal River, FL 34428-6708

Mr. William A. Passetti, Chief
Department of Health
Bureau of Radiation Control
2020 Capital Circle, SE, Bin #C21
Tallahassee, FL 32399-1741

Attorney General
Department of Legal Affairs
The Capitol
Tallahassee, FL 32304

Mr. Craig Fugate, Director
Division of Emergency Preparedness
Department of Community Affairs
2740 Centerview Drive
Tallahassee, FL 32399-2100

Chairman
Board of County Commissioners
Citrus County
110 North Apopka Avenue
Inverness, FL 34450-4245

Mr. Stephen J. Cahill
Engineering Manager
Crystal River Nuclear Plant (NA2C)
15760 W. Power Line Street
Crystal River, FL 34428-6708

Mr. Daniel R. Westcott
Supervisor, Licensing & Regulatory Programs
Crystal River Nuclear Plant
15760 W. Power Line Street
Crystal River, FL 34428-6708

Senior Resident Inspector
Crystal River Unit 3
U.S. Nuclear Regulatory Commission
6745 N. Tallahassee Road
Crystal River, FL 34428

Ms. Phyllis Dixon
Manager, Nuclear Assessment
Crystal River Nuclear Plant (NA2C)
15760 W. Power Line Street
Crystal River, FL 34428-6708

Mr. David T. Conley
Associate General Counsel II - Legal Dept.
Progress Energy Service Company, LLC
Post Office Box 1551
Raleigh, NC 27602-1551

Mr. Daniel L. Roderick
Vice President, Nuclear Projects & Construction
Crystal River Nuclear Plant (SA2C)
15760 W. Power Line Street
Crystal River, FL 34428-6708

Mr. Mark Rigsby
Manager, Support Services - Nuclear
Crystal River Nuclear Plant (SA2C)
15760 W. Power Line Street
Crystal River, FL 34428-6708

Mr. Robert J. Duncan II
Vice President, Nuclear Operations
Progress Energy
Post Office Box 1551
Raleigh, NC 27602-1551

ENCLOSURE

cc:

Mr. Brian C. McCabe
Manager, Nuclear Regulatory Affairs
Progress Energy
Post Office Box 1551
Raleigh, NC 27602-1551

Mr. Brian Moore
5559 Cactus Circle
Spring Hill, FL 34606

Ms. Gail Grimm
1007 W. Main Street
Inverness, FL 34450

Mr. John H. Ring
220 N. Big Oaks Point
Lecanto, FL 34461

Mr. Andrija (Andy) Vukmir
1498 N. Endicott Point
Crystal River, FL 34423

Ms. Dixie Hollins
Citrus County Chamber of
Commerce
P.O. Box 277
Crystal River, FL 34423

Mr. Gary W. Maidhof
Department Director
Citrus County Government
3600 W. Sovereign Path
Suite 109
Lecanto, FL 34461