From: "Graham, Keith (GE Infra, Energy, Non-GE)" <keith.graham@ge.com>
To: "George Wunder" <GFW@nrc.gov>
Date: 7/17/2007 4:12:59 PM
Subject: FW: Telcon to Discuss Draft RAI regarding ABWR Plant Medium Voltage Electrical System Design
cc: "Joseph A (GE Infra Energy) Savage" <joseph.savage@ge.com>

This message forwarded per Joe Savage's request.

Keith Graham

-----Original Message-----
From: Savage, Joseph A (GE Infra, Energy)
Sent: Tuesday, July 17, 2007 4:08 PM
To: Graham, Keith (GE Infra, Energy, Non-GE)
Subject: Re: Telcon to Discuss Draft RAI regarding ABWR Plant Medium Voltage Electrical System Design

Keith
Please forward with my concurrence noted via this email.

George
I will call you shortly to discuss the planned amendment for the ABWR DCD.

Thank you
Joe.

Sent from my BlackBerry Wireless Device

-----Original Message-----
From: Graham, Keith (GE Infra, Energy, Non-GE)
To: Savage, Joseph A (GE Infra, Energy)
Sent: Tue Jul 17 15:31:21 2007
Subject: Telcon to Discuss Draft RAI regarding ABWR Plant Medium Voltage Electrical System Design

I propose to send the following message with attachment to George Wunder. Please advise.

Thanks, Keith

Hello George,

Thank you for the opportunity to review the draft RAI for the Plant Medium Voltage Electrical System Design with your staff. We anticipate our discussions will promote a common understanding of the draft RAI and the proposed changes to the ABWR DCD.

Our team will need to ask your team some questions to ensure we understand the RAI.

Our review of some of the RAI reveal GEH will need to issue a revision to the LTR

I am attaching our responses to the proposed RAI for reference during our telcon. Note that our responses are in a draft format; our team will need additional time to prepare a formal response. I suggest an open forum discussion between our staffs during our telcon.

Regards,

Keith

Keith Graham
GE-Hitachi Nuclear Energy Americas
ABWR Licensing Team
Manager, STP 3&4 Combined License Application
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Hearing Identifier: SouthTexas34Public
Email Number: 17

Mail Envelope Properties (47838CC4.HQGWDO01.TWGWPO02.200.2000010.1.2736E0.1)

Subject: FW: Telcon to Discuss Draft RAI regarding ABWR Plant Medium Voltage Electrical System Design
Creation Date: 7/17/2007 4:12:59 PM
From: "Graham, Keith (GE Infra, Energy, Non-GE)" <keith.graham@ge.com>

Created By: keith.graham@ge.com

Recipients
"Joseph A (GE Infra Energy) Savage" <joseph.savage@ge.com>
"George Wunder" <GFW@nrc.gov>

Post Office	**Route**
TWGWPO02.HQGWDO01	nrc.gov

Files	**Size**	**Date & Time**
MESSAGE	2045	7/17/2007 4:12:59 PM
Draft RAI re ABWR Med Volt Elect Sys (071707).doc	101888	1/8/2008 2:46:28 PM
Mime.822	144075	1/8/2008 2:46:28 PM

Options
Priority: Standard
Reply Requested: No
Return Notification: None
None

Concealed Subject: No
Security: Standard

ABWR Plant Medium Voltage Electrical System Design – NRC Draft RAI (07/15/07)

1. The revised medium voltage design does not meet SECY -91-078 requirement of direct connection to transformer. It is not clear to the staff how the proposed design improves the reliability when safety-related buses and non-safety-related buses are fed from the same transformer.

Cal Tang - NUREG-1503, Section 8.2.3.4, Independence of Safety Systems During Operation or Failure of Non-Class 1E Loads (NRC Policy Issue SECY-91-078, Section II.B of Enclosure 1 to SECY-93-087), evaluates the alternate offsite preferred circuit design (which does not include provision for powering of non-Class 1E loads from the same transformer winding as Class 1E loads), and concludes that the GE design is acceptable.

Ira Poppel - Following the SECY requirement, in lieu of the alternate offsite preferred circuit design proposed by GE and approved by the NRC, does not improve plant safety because it disallows the electrical industry standard differential current transformer protection. Without an intervening non safety stub bus one of the differential current protective relay current transformers would have to be on the safety bus and directly hardwired to the other non safety buss' current transformers and the non safety protective relay (a violation of RG 1.75; isolators are precluded because of the very fast response time required to clear transformer internal faults).

The use of the stub bus allows the standard transformer protection scheme and normal over-current protection of the feeder to the safety bus. The ABWR design precludes non-safety loads on the stub bus.

2. Provide location of stub buses A4, B4, C4, A5, B5, C5, etc. The staff is concerned about propagating fire from non-safety-related bus to the stub bus if the stub buses are located near the non-safety-related PIP buses.

Cal Tang - These non-safety-related buses are located in the turbine building switchgear area. In the event a postulated fire takes out all of these non-safety related buses, the plant will be shutdown and remain in safe shutdown using the safety-related buses and emergency DGs located in the reactor building.

For a SBO event, a concurrent fire in the non-safety related switchgear area is not assumed, and thus the CTG can power the PIP and safety buses for safe shutdown. NUREG-1503, Section 8.2.3.4, Independence of Safety Systems During Operation or Failure of Non-Class 1E Loads (NRC Policy Issue SECY-91-078, Section II.B of Enclosure 1 to SECY-93-087), evaluates this aspect of the ABWR electrical system design, and concludes that this design is acceptable.

3. In several sections (including Technical Specifications), it is stated that CTG will reach operational speed and voltage in less than 10 minutes. Also, the CTG will provide power to the safety-related bus within 10 minutes. Provide actual time required for the CTG to reach operational speed and voltage. Additionally, provide the time required to close the necessary breakers to bring power to the safety-related bus.

Cal Tang - The actual time required for the CTG to reach operation speed and voltage will be specified based upon actual equipment performance. This time is not specified in the SBO Rule, 10 CFR 50.63. Rather, this rule states that if it can be demonstrated by test that the Alternate AC (AAC) power source can be started and available to power the shutdown buses within 10 minutes of the onset of station blackout, then no coping analysis is required. The ABWR is committed to use the CTG as the AAC and tests will be performed to demonstrate the capability for starting the CTG and powering the shutdown buses within 10 minutes. Refer to Table 1C-1 ABWR Design Compliance with 10CFR50.63 Regulations.

4. Table 1C-1, under article 50.63 (a)(1)(I), states that "The current plant onsite emergency power sources include three (3) independent and redundant DG divisions which are designed to supply approximately 7.2 MWe within 1 minute." Confirm that emergency DG will be connected to the safety-related bus within 1 minute. Is this consistent with accident analysis?

Cal Tang - The emergency DGs will be connected to the safety-related bus in ≤ 20 seconds. However, the loads are automatically sequenced depending on whether it is a loss of offsite power or loss of offsite power coincident with a LOCA. The accident analyses are consistent with the emergency DG startup time and the load sequencing in Table 8.3-4 D/G Load Sequence Diagram Major Loads, of the ABWR DCD.

Ira Poppel - ABWR accident analysis assumes that the diesels are on the bus in 20 seconds and then start a 1 - 2 minute autosequence of loading depending on whether it its a loss of offsite power or loss of offsite power and LOCA

5. Section 8.1.2.2 (Page 8.1-2) states that three non-Class 1E buses and one Class 1E division receive power from the single unit auxiliary transformer assigned to each load group. The above statement does not appear to be true for unit auxiliary transformer C. Please revise the statement.

Masrur Khan / Bharat Ajmani - The statement addressed in the RAI will be clarified with the following statement (underlined text = replacement text in all RAI responses):

Two power generation load groups, one PIP load group and one Class 1E division receive power from the single unit auxiliary transformer (UAT A or B). The third PIP load group and corresponding Class 1E division receive power from UAT C. PIP load groups A, B and C line up with Divisions I, II and III, respectively.

LTR Impact - LTR will be revised as noted in response to RAI-5.

6. Section 8.2.1.1 (Page 8.2-1), Item (12) is modified to discuss connection between UATs and 13.8 kV switchgear and UATs to PIP switchgear. You need to discuss connection type (i.e., non-segregated phase bus or cable bus) between PIP switchgear and stub bus and safety-related switchgear.

Masrur Khan / Bharat Ajmani – Item 12 in Section 8.2.1.1 (Page 8.2-1) will be revised with additional information (underlined text) as follows:

The non-segregated phase buses from the unit auxiliary transformers (UATs) to the output terminals of the non-safety related medium voltage (13.8 kV) switchgear, the cable buses from the UATs to the input terminals of the plant investment protection (PIP) medium voltage (4.16 kV) switchgear, the power cables between PIP medium voltage switchgear and stub bus, and power cables between the PIP medium voltage switchgear and the safety related switchgear.

LTR Impact - LTR will be revised as noted in response to RAI-6.

7. Section 8.2.1.1 (Page 8.2-1), Item (13) indicates power cables from the reserve auxiliary transformers to the input terminals of the non-safety-related medium voltage (4.16 kV) switchgear. Should this be cable bus? For clarity, 6.9 kV should be replaced as 13.8 kV and 4.16 kV.

<u>Masrur Khan / Bharat Ajmani</u> – The description in 8.2.1.1 is accurate, the conductors are not cable bus. Therefore, no change in the type of conductor is required. The medium voltage 6.9 kV in item 13 of Section 8.2.1.1 (Page 8.2-1) will be replaced as <u>13.8 kV and 4.16 kV.</u>

LTR Impact - LTR will be revised as noted in response to RAI-7.

8. Section 8.2.1.1 (Page 8.2-2), Item (14) is confusing as modified. CTG is connected to 13.8 kV switchgear. Power cables (or cable bus) from the 13.8kV/ 4.16 kV transformer to 4.16 kV stub bus (CTG 3).

<u>Masrur Khan / Bharat Ajmani</u> – Section 8.2.1.1 (Page 8.2-2), Item (14) will be revised with additional details as required in the RAI. The revised item 14 of Section 8.2.1.1 will read as –

The power cables <u>between</u> the combustion turbine generator and the input terminals of the medium voltage <u>13.8 kV CTG 1 switchgear and interconnection power cables between 13.8 kV and 4.16 kV switchgear and 13.8 kV/4.16 kV power transformer in accordance with power distribution configuration shown in single line diagram (Figure 8.3-1, sheet 1).</u>

LTR Impact - LTR will be revised as noted in response to RAI-8.

9. Section 8.2.1.2 (Page 8.2-3) states that the generator circuit breaker provided is capable of interrupting symmetrical and asymmetrical fault current of 440 kA momentary at 5 cycles after initiation of the fault. Please explain why the symmetrical and asymmetrical fault current values are same. Is there any problem of obtaining a breaker with such high interrupting current capability.

<u>Masrur Khan / Bharat Ajmani</u> – The symmetrical and asymmetrical fault current values are not the same. The statement in Section 8.2.1.2 (Page 8.2-3) will be revised to read as-

The generator circuit breaker provided is capable of interrupting a maximum symmetrical and asymmetrical fault current<u>s</u> of <u>275 kA and </u>440 <u>kA, respectively.</u>

The breakers with the above interrupting rating are being manufactured and there should be no problem in obtaining them.

LTR Impact - LTR will be revised as noted in response to RAI-9.

10. Page 8.2-4, Insert B, Please clarify whether the tap changers for RATs are manual or automatic. The UAT tap changers are automatic per insert A.

Masrur Khan / Bharat Ajmani – The RAT tap changers are also automatic. Page 8.2-4, Insert B will be revised to reflect automatic tap changer.

LTR Impact - LTR will be revised as noted in response to RAI-10.

11. Section 8.2.1.3 (Page 8.2-5), the last sentence (The alternate preferred power feed turns down between the Control and Reactor Building and enters.) As modified is incomplete. Please modify appropriately.

Masrur Khan / Bharat Ajmani – The continuation of the last sentence on page 8.2-5 that was deleted on page 8.2-6, will be reinstated. This will resolve concern addressed in the RAI.

LTR Impact - LTR will be revised as noted in response to RAI-11

12. Section 8.2.2.1 (Page 8.2-7), provide a discussion how ABWR design will meet GDC 2 and 4 as discussed in SRP 8.2, Revision 4.

James Cook - GDC 2 and 4 have always applied to the safety-related components of the offsite power system for the ABWR. SRP 8.2 does not establish new guidance on this issue.

Keith Graham - In general, only the departures should be subject to new NRC guidance, not the entire system design. Each departure from the DCD will be evaluated on a case-by-case basis.

Masrur Khan / Bharat Ajmani – Section 8.2 and SRP 8.2 pertain to off-site power system. BE Civil Engineering confirmed that offsite SSCs design will meet relevant GDC 2 and 4 requirements per SRP without any exceptions.

13. Section 8.2.5 included main transformer and reserve auxiliary transformer ratings. Include unit auxiliary transformer ratings. Also, include tap changer information (automatic or manual).

Masrur Khan / Bharat Ajmani – The required additional information in the RAI will be included in Section 8.2.5.

LTR Impact - LTR will be revised as noted in response to RAI-13.

14. Section 8.3.1.0.1 (Page 8.3-2), the modified last paragraph states that "the non-Class 1E and the Class 1E switchgear interrupting ratings are chosen to be capable of clearing maximum expected fault current. The steady state ratings are chosen to carry the maximum expected normal currents. The 13.8 kV/4.16 kV switchgear is respectively rated at 15kv/4.76kV." This section should discuss Non-Class 1E distribution system. Class 1E distribution system should be discussed in Section 8.3.1.1.1. It is not clear what is meant by steady state ratings. Suggest retaining last sentence of original writeup (Instrumentation and control power is from non-Class 1E, 125 VDC power system.).

<u>Masrur Khan / Bharat Ajmani</u> – The Class 1E discussion is already addressed in Section 8.3.1.1.1. It will be deleted from the Section 8.3.1.0.1.

It is clarified in response to RAI that the steady state ratings in DCD are addressed in context with continuous ratings. The DCD section clarifies these ratings by stating 'the maximum expected normal currents'.

The non-class 1E Instrumentation and control power is from AC sources and not 125 V DC (Reference: Single line diagram Figure 8.3-2 in DCD). Therefore, the deletion of last sentence on page 8.3-2 is correct.

LTR Impact - LTR will be revised as noted in response to RAI-14.

<u>Ira Poppel</u> - they probably mean switchgear control power - on ABWR I&C power is 120 vac derived from regulating transformers

15. Page 8.3-44, Originally, V2 trays were for high level signal and control. Revised tray designation does not include these cables. Provide a basis for not including these cables. Additionally, please verify that power cables (V3) are routed in flexible metallic conduit under the raised floor of the control room (Refer to last paragraph of Item (4)).

<u>Evan Heacock</u> –WE need to better understand the NRC concern on the removal of tray strictly for control circuits.

WE acknowledge that the new V2 voltage level cables will be routed in metallic conduit or separate tray/raceway under the raised floor in the control room and not V3 (V3 is now 4.16kV cable which will not be in the control room).

16. SR 3.8.1.9 (TS, Page 3.8-11), provide basis for fixed power factor of 0.9. The power factor should be design load power factor. For SR 3.8.1.9.a, frequency value is missing. Please provide this value.

<u>Tom Demitrack</u> - The basis for the fixed power factor value is Regulatory Guide 1.9, Rev. 3 (July 1993). RG 1.9 Section 2.2.7 states to perform the Single-load rejection test while operating at a power factor between 0.8 and 0.9. Per the DCD and the LTR the Design Power Factor is 0.8 (Section 8.3.1.1.8.2)

The NRC states the power factor should be the design load power factor. This statement is consistent with RG 1.9 Rev. 4 Section 2.2.7, Largest Load Rejection Test. However, the ABWR DCD is based on RG 1.9 Rev. 3.

The NRC stated that the frequency value is missing and to provide the value. The basis of the value is described in the bases. It cannot be provided at the time of COLA since it depends on the actual purchased equipment. It will be based on the following: During recovery from transients caused by step load increases or resulting from the disconnection of the largest single load, the speed of the diesel generator unit will not exceed the nominal speed plus 75% of the difference between nominal speed and the over-speed trip setpoint or 115% of nominal, whichever is lower (see Position 1.4 of Regulatory Guide 1.9).

17. SR 3.8.1.10 (TS, Page 3.8-11), provide basis for fixed power factor of 0.9. The power factor should be design load power factor. This surveillance as written (verify each DG operating at a power factor 0.9 does not trip and voltage is maintained [ ] V during and following a load rejection of a load □ [5000] V and [ ] kW.) Appears to be incorrect. It should read: "Verify each DG operating at a power factor [0.9] does not trip and voltage is maintained [5000] V during and following a load rejection of a load □ [7200] kW and [9000] kW."

<u>Tom Demitrack</u> - SR 3.8.1.10 was not modified by the LTR.

The basis for the fixed power factor value is Regulatory Guide 1.9, Rev. 3 (July 1993). RG 1.9 Section 2.2.8 states to perform the Single-load rejection test while operating at a power factor between 0.8 and 0.9. Per the DCD and the LTR the Design Power Factor is 0.8 (Section 8.3.1.1.8.2)

The NRC states the power factor should be the design load power factor. This statement is consistent with RG 1.9 Rev. 4 Section 2.2.8, Design Load Rejection Test. However, the ABWR DCD is based on RG 1.9 Rev. 3.

The NRC stated that the SR is written incorrectly. GE is in agreement the SR should have been written as: "Verify each DG operating at a power factor ≤ 0.9 does not trip and voltage is maintained ≤[ ] V during and following a load rejection of a load ≥ [5000] V kW and ≤ [ ] kW." Per RG1.9 Rev. 3 the load for the test should be equal to 90 to 100 percent of the continuous rating of the EDG. Therefore, based on a continuous rating of 7200 kW and RG 1.9 Rev. 3, the SR should be written as follows. Verify each DG operating at a power factor ≤ 0.9 does not trip and voltage is maintained ≤[ ] V during and following a load rejection of a load ≥ 6480 kW and ≤ 7200 kW.

<u>Ira Poppel</u> - in the absence of design information but knowing it was "enveloping", the diesel generators at Lungmen were rated at 7.2 MWe and 9 MVA implying a .8 power factor

Masrur Khan / Bharat Ajmani - WE concur with the RG 1.206 Section C.IV.3.3.3 statement “Generic TSs contains values in brackets [ ]. These brackets are placeholders indicating that the NRC’s review is not complete and represent a requirement that COL applicants replace the values in brackets with final plant-specific values. The values in brackets are neither binding nor part of the DCR.” Consequently GE will treat the TS brackets in the LTR in the same manner as it was in the DCD. The applicant’s COLA will address the bracketed TS information in the following manner:

1. When the TS values have been finalized at the COLA stage, the values within the brackets will be updated, including blank brackets and the brackets removed.
2. When a TS value is subject to detail design and procurement of major hardware, the information or blanks will be retained in brackets at the COL submittal stage, subject to disposition before fuel load.
3. Remaining bracketed information will be finalized and TS brackets will be removed before fuel load.

18. Technical Specification section 3.8.1 Required Action A.2 (TS, Page 3.8-1), requires verification that the CTG is functional by verifying the CTG starts and achieves steady state voltage and frequency in less than 10 minutes. The steady state voltage and frequency should be defined as 13.8kv ± 10% and 60 Hz ± 2%. Please modify as follows: “Verify the CTG is functional by verifying the CTG starts and achieves steady state voltage (13.8 kV ± 10%) and frequency (60 Hz ± 2%) in less than 10 minutes.” This comment is applicable to other places.

ABWR TS Required Actions A.2 (TS, Page 3.8-1) does not currently specify the explicit steady state voltage and frequency values for the CTG. The values will be located in FSAR Section 9.5.13.19 as indicated in the LTR. We do not see a need to include the explicit values in the TS.

19. In Section 8.2.3 (Page 8.2-9), it is stated that the normal steady state frequency of the offsite transmission network shall be within plus or minus 2 hertz of 60 Hz. Pump flow will be reduced for reduced frequency. Is the frequency variation considered in the accident analysis?

Ira Poppel - It is understood that the flow of all safety related pumps (other than RCIC) will be directly affected by grid or diesel generator frequency. During the design process the lower available flow at the minimum allowed frequency will be accounted for by a combination of the appropriate choice of pump head vs flow curves or the accident analysis minimum allowed flows.

20. DG surveillance verifies that DG frequency is □ [58.8] Hz and [61.2] Hz. Pump loading is proportional to cube of speed and hence cube of frequency. Please confirm that pump loading properly considered the effect of increased frequency.

Ira Poppel - The pump shaft load will vary with the cube of the pump speed/frequency. During the design process the increased loads at the maximum allowed frequency will be accounted for by the proper choice of pump motor rated power and service factor. Similarly the diesel generators will be sized to account for the increased loading attributable to the higher frequency.